NEAR-TERM AND LONG-TERM CARBON DIOXIDE SEQUESTRATION POTENTIAL IN THE UNITED STATES USING BIO-ENERGY WITH CARBON CAPTURE AND STORAGE

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NEAR-TERM AND LONG-TERM CARBON DIOXIDE SEQUESTRATION POTENTIAL IN THE UNITED STATES USING BIO-ENERGY WITH CARBON CAPTURE AND STORAGE

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This work is part of a larger effort at the Oak Ridge National Laboratory to investigate the potential of carbon capture and sequestration using Bio-Energy with Carbon Capture and Storage (BECCS) in the U.S. This thesis focuses on the CO_2 capture side of BECCS through power plant performance and economics simulations as well as applications of different CO_2 cost account equations to evaluate the cost of BECCS.

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LIST OF ABBREVIATIONS

ASU	Air separation unit
BECCS	Bio-Energy with Carbon Capture and Storage
BILT	Biomass Information Logistics and Transport
CAC	CO_2 avoidance cost
CCS	Carbon capture and storage
CO_2	Carbon dioxide
DAC	Direct air capture
E	Emissions intensity (in tonne CO_2 per MWh)
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
GE	General Electric
GHG	Greenhouse gas
HDPE	High density polyethylene
IECM	Integrated Environmental Control Model

IGCC	Integrated gasification combined cycle
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized cost of electricity (in $ per MWh)
MEA	Monoethanolamine
NET	Negative emissions technology
NGCC	Natural gas combined cycle
NMP	N-Methyl-2-Pyrrolidone
O&M	Operating and maintenance
OR-Sage	Oak Ridge Siting Analysis for power Generation Expansion
PC	Pulverized combustion
PET	Polyethylene terephthalate
TSP	Total Suspended Particles

SUMMARY

According to a special report released by the Intergovernmental Panel on Climate Change (IPCC) in 2018 titled “Global Warming of 1.5°C”, in order to limit the increase in mean global temperature to 1.5°C from the pre-industrial age, the world must achieve net-zero carbon emissions by 2050. CO_2 capture technologies from flue gas are being developed to help reach this goal. These technologies, however, can only help reduce CO_2 emissions. Additional, negative-emissions technologies are needed to remove CO_2 from the atmosphere and thus reduce the atmospheric CO_2 concentration. One such method of removing CO_2 from the atmosphere is Bio-Energy with Carbon Capture and Storage (BECCS), which employs biomass-fired power plants with the capability to capture 90% of incoming CO_2 through chemical absorption with monoethanolamine (MEA) for example. Since biomass draws CO_2 from the atmosphere as it grows, BECCS can remove CO_2 from the atmosphere and, after combustion, store it underground through CCS.

This thesis evaluates the CO_2 sequestration potential of implementing BECCS power plants in the U.S. through power plant performance simulations. Power plant performance and economic estimates were modeled using the Integrated Environmental Control Model (IECM). Calculations were carried out under a near-term scenario (2020) and under a long-term scenario (2040).

An estimate for the CO_2 sequestration potential, biomass utilization, and cost of BECCS in the years 2020 and 2040 was obtained. Pulverized combustion (PC) and integrated gasification combined cycle (IGCC) power plants were modeled to run on biomass feed. Potential sites for BECCS power plants were determined by the proximity of saline

aquifers, protected lands, and populated regions. Protected lands and U.S. EPA non-attainment areas were excluded as well. The population density criteria were chosen to be similar to those of coal-fired power plants and less than those of a nuclear plant of comparable size. Sites too far from saline aquifers were excluded due to concerns with transportation costs. Costs and emissions associated with the harvesting, pretreatment, and transport of biomass feed were evaluated to determine more accurate results. Power plant performance and economics were simulated to determine parameters like net MWh produced, levelized cost of electricity (LCOE), emissions intensity (in tonnes CO_2 per MWh), capital costs, and operation and maintenance (O&M) costs. Sensitivity analyses were performed to determine parameters that the LCOE was most sensitive to in both PC and IGCC power plants.

Results indicated that the LCOE ranges between $140 and $180 per MWh in the 2020 scenario, and between $130 and $180 per MWh in the 2040 scenario. The cost of carbon capture ranges between $35 and $176 per tonne of CO_2 depending on the accounting equation used, power plant configuration, and extent of BECCS deployment. Under a near-term scenario using up to 206 million tonnes per year of biomass, roughly 181 million tonnes of CO_2 can be sequestered annually in the U.S. at CO_2 avoidance costs ranging between $62 and $137 per tonne CO_2. The CO_2 avoidance cost is a measure used to compare the effectiveness of different carbon reduction options, and represents the cost of reducing CO_2 emissions to the atmosphere while producing the same amount of product from a reference plant. The CO_2 avoidance cost considers the increase in CO_2 produced per MWh in power plants with CCS. There is an increase in emissions since capturing CO_2 requires energy, and that energy comes from fuel burned at the same plant. Long-term

scenarios have the potential to use 740 million tonnes of biomass and sequester 737 million tonnes of CO_2 per year at avoidance costs ranging between $45 and $85 per tonne CO_2 depending on power plant configuration, type of fuel, and extent of biomass utilization. It should be noted that 1 tonne of biomass can approximately sequester 1 tonne of CO_2 from the atmosphere if used towards BECCS. Sensitivity analyses identified the boiler efficiency, solvent regeneration heat requirement, fuel cost, and CO_2 compression energy as the most significant parameters in a PC system. For IGCC setups, the turbine inlet temperature and fuel cost are the most significant parameters that influence electricity costs.

Findings concerning the sequestration potential and cost of BECCS, as well as potential ways to decrease the cost of BECCS, are discussed in the thesis. Based on the results and the climate goals outlined by the Paris Agreement, BECCS has the potential to sequester roughly 1 billion tonnes of CO_2 annually in 2040, which is about 25% of what is needed to achieve carbon neutrality in the U.S. In addition, BECCS can produce electricity at rates competitive with some neutral emissions technologies. The avoidance cost of BECCS is lower than such neutral emissions technologies as solar and offshore wind. CO_2 avoidance costs using reference case power plants with carbon capture and storage show that the cost of sequestering CO_2 from the atmosphere using BECCS is between $29 and $142 per tonne of CO_2. This thesis serves to advance the understanding of the economics and implementation of BECCS through power plant simulations, supply chain estimates, and the application of different CO_2 accounting equations.

1. INTRODUCTION

Currently, almost all forms of anthropogenic activities contribute to greenhouse gas (GHG) emissions.[1, 2] According to the U.S. Environmental Protection Agency (EPA), the largest source of GHG emissions from human activities in the U.S. is from burning fossil fuels for energy including electricity, heat, and transportation.[3, 4] The U.S. Energy Information Agency (EIA) estimates that the U.S. emitted roughly 5.1 billion tonnes of energy-related CO_2 in 2017, while the global energy-related CO_2 emissions totaled roughly 32.5 billion tonnes.[4] Transportation was estimated to be the largest share of CO_2 emissions in the U.S., with a share of roughly 28.2% in 2018.[4] This is primarily from fossil fuels being burned to fuel cars, planes, ships, and trucks. Most of the fuel used for transport is petroleum based. Electricity production for homes is the second largest contributor to CO_2 emissions, where around 63% of electricity production comes from coal and natural gas combustion.[4] The industry in the U.S. accounts for 22% of CO_2 emissions, primarily from energy consumption and emissions from chemical reactions. Agriculture accounts for roughly 10% of yearly CO_2 emissions, namely from livestock, agricultural soils, and rice production.[4]

According to the latest report by the Intergovernmental Panel on Climate Change (IPCC), in order keep the rise in global mean temperature since the pre-industrial age to 1.5°C, the world must employ deep emissions reductions.[5] Furthermore, findings from this report suggest that limiting global warming to 1.5°C instead of 2°C would reduce the challenging impacts on the ecosystem, lessen extreme weather, and diminish ecosystem loss.[5] Countries part of the Paris Agreement have agreed to try to limit this temperature increase

to 1.5°C.[5] Findings of the IPCC report suggest that the world must achieve net-zero CO_2 emissions by 2050 to limit global warming to 1.5°C.[5] Thus, to achieve net-zero emissions, there is significant interest in developing technologies for carbon capture and geologic storage among other net-zero or net-negative emission technologies. The main carbon capture technologies investigated thus far can be divided into the following groups: chemical absorption, physical absorption, adsorption, membrane separation, and biological separation.

CO_2 capture through absorption can be divided into three categories: pre-combustion capture, post-combustion capture, and oxyfuel capture.[6] Post combustion capture, i.e., CO_2 capture from flue gas mainly through chemical absorption, offers the advantage of retrofitting to preexisting coal power plants. The issue, however, is that chemical absorption is high-energy demanding and will decrease the net efficiency of the power plant. The regeneration energy requirement of the solvent used in most cases is the bottleneck of the capture process. The main chemical reagents used in post-combustion chemical absorption are monoethanolamine (MEA), KS-1, and KS-2 (sterically hindered amines produced by Mitsubishi), and ammonia.[6] Another drawback with post-combustion CO_2 capture, especially when using MEA, is that the flue gas temperature and composition must be carefully monitored and controlled. High temperatures can cause thermal degradation of MEA and also favor CO_2 release from the MEA, i.e., the reversed reaction. Similarly, the performance of MEA is hampered by the presence of acidic gases like SO_2 and NO_2 since these acid gases can form heat stable salts with MEA, and thus must be removed beforehand.[6] Furthermore, particulates and fly ash need to be removed from the flue gas before it enters the absorption column. Particulates present in the absorption

column can lead to foaming and decreased capture efficiency of the solvent. Lastly, amines like MEA are highly toxic and can cause significant harm to the environment if improperly disposed.[7]

Pre-combustion capture of CO_2 is generally proposed in Natural Gas Combined Cycle (NGCC) power plants and Integrated Gasification Combined Cycle power plants (IGCC), where CO_2 is separated from the feed synthesis gas produced from biomass gasification. Generally, physical solvents are used, namely, Selexol, Purisol, and Rectisol.[8] The CO_2 loading capacity of these physical solvents is determined by Henry's law, i.e., a linear dependency between partial pressure and loading capacity. Figure 1 illustrates the differences in loading capacities as a function of partial pressure for chemical and physical solvents used in CO_2 capture. The physical absorption of CO_2 is facilitated by high pressures and low temperatures. Physical solvents can be regenerated at low energy costs by decreasing the pressure. High partial pressures of CO_2 in the syngas help drive this absorption process.

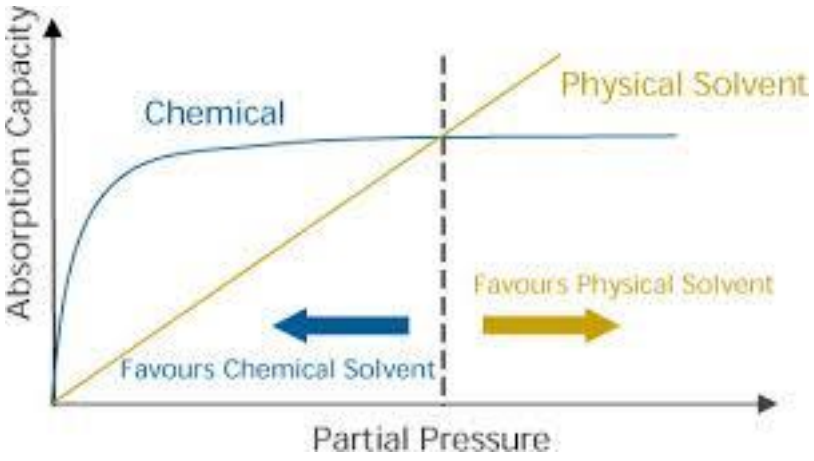

Figure 1: Loading capacities of solvents as a function of partial pressure of CO_2.[8]

Selexol, Purisol, and Rectisol are the three main physical solvents used in the industry for pre-combustion capture of CO_2. Selexol uses a dimethyl ether of polyethylene glycol for the capture of CO_2. It can also be used to capture H_2S in the syngas, with a selectivity of H_2S to CO_2 of roughly 9-10.[9] The Selexol process can be conducted in a sweet shift or sour shift mode. In sour shift, H_2S is removed before CO_2, whereas in the sweet shift, CO_2 is removed before H_2S. In general, sour shift is seen as the more energy efficient capture mechanism as it requires roughly 4.6 times less shift steam than the sweet shift process.[10] The Purisol process uses N-Methyl-2-Pyrrolidone (NMP) as solvent.[11] In the Rectisol process, chilled methanol is used at a temperature of -40°C to -62°C. The selectivity of H_2S/CO_2 is roughly 6, which is lower than that of Selexol. At high temperatures, Rectisol exhibits a very high affinity for H_2S and allows for a deeper removal of sulfur. The main disadvantage with the Rectisol process, however, is the large energy costs associated with refrigerating the solvent.[12]

Oxyfuel combustion is another method of capturing CO_2. It involves burning the fuel in nearly pure oxygen instead of air. The aim of this process is to generate a flue gas stream with high concentrations of CO_2 and water vapor, which can then be purified through dehydration and other low temperature processes.[13] Furthermore, this process requires flue gas recycling to control the flame temperature of the combustion reaction.[13] Without recycling, the temperature can become uncontrollably high and damage the equipment. In general, oxyfuel combustion power plants will have the following units: an air separation unit (ASU) to produce pure oxygen gas, a boiler or gas turbine for combustion, a flue gas processing unit to clean the flue gas, and a CO_2 processing unit for carbon capture and storage. Oxyfuel combustion in turbine-based power plants can be classified as CO_2-based

gas turbine cycles and water-based gas turbine cycles depending on the relative concentrations of CO_2 and water in the entering flue gas stream.[14] Turbines operate at relatively high pressures, and thus demand a supply of high-pressure oxygen. In turbine oxyfuel power plants, the majority of the energy is used by the air separation unit and the CO_2 capture unit. Gas turbines are required to operate at high pressures since high flowrates of oxygen are required to keep the temperature of the reaction within the material limit of the turbine. The high cost associated with pure oxygen makes this cooling mechanism expensive.

CO_2-based cycles can be retrofitted to NGCC power plants, as demonstrated by Bolland et al. (1992). The main components of this type of plant is a Brayton Cycle gas turbine and a heat recovery steam generator (HRSG) with a Rankine Cycle.[15] The exhaust gas from the HRSG is cooled, and most of the water is condensed, thus the recycle stream only contains CO_2. This CO_2 helps control the temperature of the reaction for cooling purposes. Recycle ratios of around 90% are used to control the turbine inlet temperature to acceptable levels. Water based cycles use the condensed water from the HSRG to cool the reaction instead of CO_2. One such method is the clean energy systems cycle (CES) developed by Clean Energy Systems, Ltd.[13] In their proposed system, condensed water is injected into the gas generator that burns the fuel at high pressure with oxygen. The condensed water controls the temperature and uses an input fuel to the turbine of 90% steam and 10% CO_2. The CO_2 in the mixture is separated using condensation.

Vacuum swing adsorption of CO_2 from flue gas is a promising technology for CO_2 capture. Carbon-based adsorbents exhibit high adsorption capacity towards CO_2 at ambient conditions. The main forms of carbon-based adsorbents used are activated carbon, carbon

nanotubes, and carbon black. Research by Zou et al. (2001) indicates that carbon-based adsorbents exhibit high CO_2 adsorption capacities, but this diminishes at higher temperatures. Another class of adsorbents includes zeolites.[16] The main disadvantage with zeolites, however, is that there is no full reversibility through thermal regeneration. Adsorption properties of solid adsorbents are governed by the nature and strength of the force fields and their distribution across the surface and pores of the adsorbent. These depend on the purity, crystal structure, and size and framework of the adsorbent.[17]

Micro and mesoporous silica materials show an inherent CO_2 adsorption capacity due to the presence of silanol groups on the surface. Surface silanol groups help facilitate proton transfer, which is an integral step in CO_2 adsorption.[18] These materials exhibit weakly basic properties and offer model CO_2/N_2 and CO_2/CH_4 selectivity.[19] Ideal materials for adsorptive capture of CO_2 should have a combination of the following characteristics: high CO_2 absorption capacity, fast kinetics, high CO_2 selectivity, low regeneration energy requirements, low cost, and high stability.[20]

Membranes can be used to capture CO_2 both before and after combustion of syngas. In pre-combustion capture, CO_2 is separated from H_2 and in post combustion capture, CO_2 is separated from N_2. There are three types of membranes that are used in CO_2 capture: non-dispersive absorption with porous membranes, gas permeation membranes, and supported liquid membranes.[21] The main advantages of membrane-based technologies are low operating cost, low energy requirements, and flexible operating conditions.[22] The main issues that hamper membrane performance are membrane fouling and the high cost associated with compression.

Scientists have demonstrated that certain biological processes can be used to sequester CO_2. [23, 24] Microalgae and cyanobacteria with high growth rates have been shown to fix carbon at rates faster than terrestrial plants.[23, 24] These organisms take their energy from the sun and can be grown in conditions that would be too harsh for terrestrial plants. These organisms, however, can have wide ranging, unpredictable effects on other species in the food chain and thus need to be monitored very carefully before large-scale implementation. In order to achieve carbon neutrality by 2050, scientists have looked into ways of removing CO_2 from the atmosphere instead of separating CO_2 from emissions. These are called negative emissions technologies (NETs).[25] The main negative emissions technologies that have shown promise in removing CO_2 from the atmosphere are: afforestation and reforestation, Bio-Energy with Carbon Capture and Storage (BECCS), land management and CO_2 fixing in soil, enhanced weathering, direct air capture (DAC) of CO_2, and ocean fertilization. Carbon capture is a critical component in both DAC and BECCS and can be performed using the previously mentioned methods.

BECCS is a negative emissions technology which involves retrofitting preexisting coal power plants to handle biomass feed and have the capacity to capture, transport, and store CO_2. By switching the fuel used from coal to biomass, BECCS has the potential to remove CO_2 from the atmosphere. Hypothetically, this is because the CO_2 fixation involved in plant growth is a closed cycle process and is orders of magnitude faster than carbon fixation involved in coal formation. In general, coal power plants can be used in pulverized combustion (PC) or in integrated gasification combined cycle (IGCC) power plants. PC power plants have the capability of running pelletized biomass feed, whereas IGCC power plants have the capability of running both pelletized and non-pelletized feed. Figure 2

illustrates the flow of CO_2 involved in BECCS**;** from the atmosphere to where it is captured and stored.

BECCS combines electricity production from biomass with geological carbon storage. The U.S. has the potential to produce between 750 to 1050 million tonnes of biomass per year by 2050.[26] The biomass used towards BECCS includes energy crops, forest residues, whole trees, and agricultural residues. Research by Baik et al. (2018) shows that around 25% of these biomass resources are located near potential sites for geological storage of CO_2.[27]

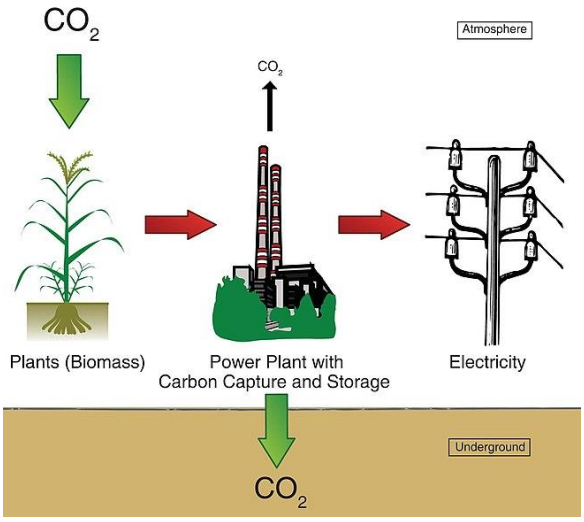

Figure 2: Flow diagram of CO_2 captured in BECCS. [28]

Another form of NETs involving CO_2 fixation through plant growth is afforestation and reforestation. This method is very inexpensive compared to other methods since no technical infrastructure for processing is required.[29] However, it requires large, ever growing amounts of land. Capacity estimates include roughly 1.1-3.3 billion tonnes of CO_2 removed from the atmosphere per year using around 320 million to 970 million hectares of land, which translates to roughly 20-60% of current global area of arable land.[30] Potential issues with this method include biodiversity related issues, nitrous oxide

emissions, requirements for large amounts of fertilizers, and disruption of pretexting forests. Widespread changing of forests can also lead to climate change through evapotranspiration, changes in albedo and cloud cover, and thus the method must be explored to greater extent before it can be implemented. There is also an ethical concern of converting land used for food production to CO_2 sequestering hubs. Figure 3 illustrates the different parts of the carbon cycle in afforestation/reforestation.

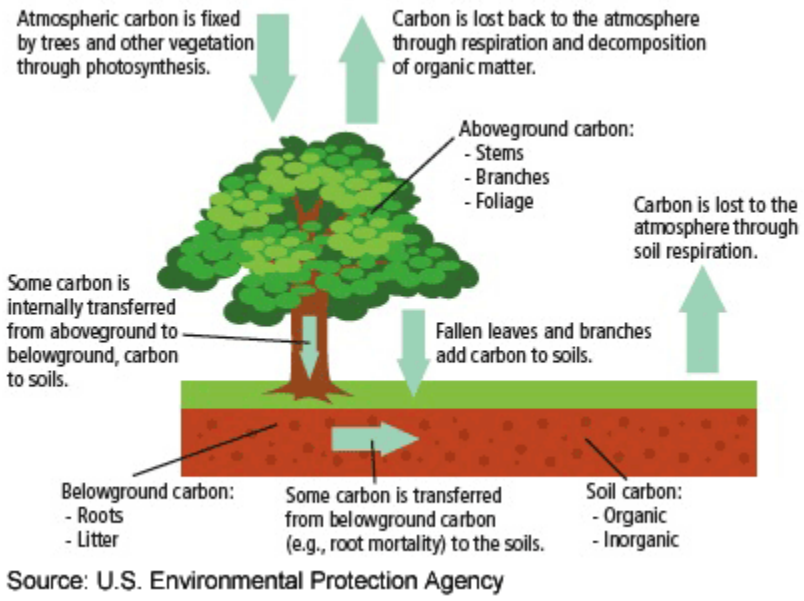

Figure 3: Schematic illustrating CO_2 capture using afforestation/reforestation.[31]

Unlike BECCS and afforestation/reforestation, enhanced weathering allows for CO_2 capture without the use of plants. Enhanced weathering involves speeding up natural processes that are already slowly absorbing CO_2 in the environment. For example, when silicate or carbonate materials dissolve in rainwater, CO_2 is slowly removed from the atmosphere. Equations 1 and 2 presented below describe the CO_2 absorption mechanism in forsterite (Mg_2SiO_4) and calcite ($CaCO_3$):[32]

$$Mg_2SiO_4 + 4CO_2 + 4H_2O \rightarrow 2Mg^{2+} + 4HCO_3^- + H_4SiO_4 \quad (1)$$

$$CaCO_3 + CO_2 + H_2O \rightarrow Ca^{2+} + 2HCO_3^- \quad (2)$$

Rainwater and bicarbonate ions eventually end up in the ocean where the captured CO_2 is converted into carbonate minerals by the activity of calcifying organisms. The precipitate carbonate sinks to the bottom of the ocean, while most of the carbonate is redissolved under higher pressures at the bottom of the ocean. The calcification of carbonate ions can be expressed by Equation 3 presented below.

$$Ca^{2+} + 2HCO_3^- \rightarrow CaCO_3 + CO_2 + H_2O \quad (3)$$

The decrease in pH of ocean water can, however, be harmful to many calcifying ocean organisms. At lower pHs, calcifying organisms require higher loads of carbonate in the water. Under scarce carbonate operating conditions, the structures of these organisms are vulnerable to dissolution. Figure 4 describes the geological carbonate-silicate cycle.

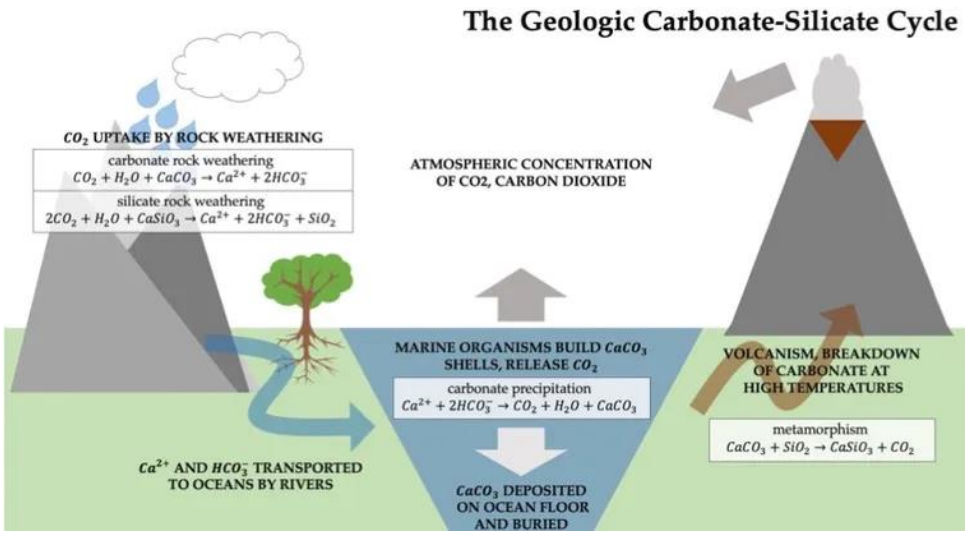

Figure 4: Geological carbonate-silicate cycle that can be enhanced for CO_2 capture.[33]

Ocean fertilization involves using planktonic algae and other microscopic plants which can convert CO_2 to organic matter. The photosynthesis process of these microbes depends on the availability of nutrients among other factors.[30] One such method is focusing on iron as a micronutrient due to large ratios of iron to carbon in plankton. However, the drawbacks of this process include the uncontrollable nature of plankton, limiting factors like availability of silicon, competition with other organisms, and tolerable pH ranges. Furthermore, increasing iron concentration in water can inadvertently lead to toxic algal blooms through the facilitation of diatom growth. Furthermore, due to the complex nature of the food chain, the effects of changing plankton community concentration can have adverse unpredictable effects on the higher trophic levels. Figure 5 illustrates ocean fertilization through iron loading.

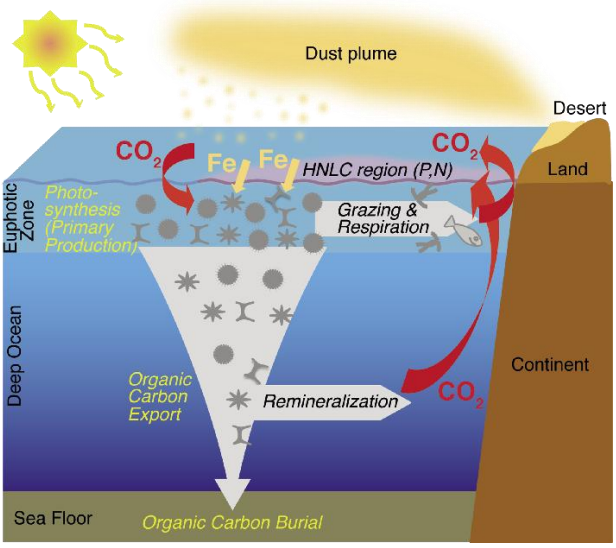

Figure 5: CO_2 capture through ocean fertilization. [34]

Direct air capture (DAC) involves the separation of CO_2 from the atmosphere by flowing air over a contactor that selectively separates CO_2.[30] DAC is hindered by the low

concentration of CO_2 in the atmosphere, which effectively diminishes the driving force for reactions. Large capital costs are expected since large surface area contactors are required to speed up the reaction. Furthermore, a lot of the solvents have high regeneration heat requirements. Research conducted by Keith et al. (2018) claims that it is possible to capture and store CO_2 from the atmosphere at rates ranging from $94 to $232 per tonne of CO_2.[35] Unlike BECCS and afforestation/reforestation, DAC is not constrained by large land requirements. DAC facilities are still a novel concept, and most existing DAC facilities use either strong basic solutions like KOH and NaOH or solid supported amines.[36]

There are two types of power plants that can be used in BECCS: pulverized combustion (PC power plants) and integrated gasification combined cycle (IGCC power plants). Pulverized combustion power plants have been shown to be able to run on pelletized biomass feed whereas IGCC power plants can run on both pelletized and non-pelletized feed. In pulverized combustion, coal is ground into very fine particles of roughly 100 mm and is then blown into the furnace.[37] This allows for the entire volume of the furnace to be used for combustion. The particles burn in the suspension and then transfer heat into the steam cycle. Research by Strauss et al. (2014) show that PC power plants can run on biomass with very little modification.[37, 38] The only restriction however is that the biomass is required to be pelletized, i.e., reduced in moisture content before it can be pulverized.

PC power plants in this thesis were modeled to include SOx and NOx removal, mercury removal, and ash disposal. SOx control was modelled using flue gas desulfurization (FGD) through wet scrubbing. Here, a slurry of limestone is used to capture SOx emissions in the flue gas through the chemical reactions presented below in Equations 4 and 5:[39]

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2 \text{ (limestone)} \quad (4)$$

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O \text{ (lime)} \quad (5)$$

NOx emissions were controlled in the furnace through low nitrous burners (LNB) and hot-side selective catalytic reduction (SCR). LNBs are designed to control air and fuel mixing at each burner, which allows for more branched and larger flames. This reduces peak flame temperature, which significantly reduces NOx production. In SCR, NOx is removed in a two-stage process. Flue gas is injected with ammonia and is then passed over a catalyst, where the following reactions take place:[40]

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (6)$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \quad (7)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (8)$$

Particulates were captured using electrostatic precipitators (ESP). There are three main steps in the particulate capture using ESP: particle charging, particle collision, and particle removal. A pair of electrodes are used to charge plates; one plate is for discharge and the other for collection of particles. The ESP converts AC voltage to DC voltage. An electric field is formed, and the gas between the electrodes is ionized. Particles that enter this field are negatively charged and are collected on the positively charged collection electrode.[41]

Carbon capture and storage in PC power plants was carried out at the end using chemical absorption with MEA, transport through pipelines, and geological storage in saline aquifers. The captured CO_2 is compressed to supercritical conditions of 13.8 MPa and is then injected underground in saline aquifers for storage. Supercritical conditions are favored for CO_2 transport since under supercritical conditions, CO_2 will have a high density and low viscosity and surface tension.[42] These conditions make it easier to transport CO_2

in pipelines because CO_2 exhibits liquid-like densities but gas-like viscosities. This combination allows for much higher throughput with significantly less drag. The transported CO_2 is required to be sufficiently dried. Any liquid water present during transport will dissolve CO_2 to form carbonic acid, which over time can degrade steel alloys used in pipelines.[43]

There are two primary trapping mechanisms in CO_2 storage with geological formations: structural and stratigraphic.[44] In structural storage, CO_2 is dropped behind a dome-shaped seal, whereas stratigraphic storage traps CO_2 through changes in porosity and permeability. There are three secondary trapping mechanisms that are used to increase the capture security: capillary trapping, mineral trapping, and solubility trapping. Capillary trapping involves trapping residues phases within the reservoir, mineral trapping involves the conversion of CO_2 into stable carbonate minerals, and dissolution involves trapping CO_2 in saline aquifers.

IGCC power plants have the capability to run on both pelletized and non-pelletized fuel. Unlike PC, in IGCC power plants, the biomass fuel is first gasified into synthesis gas (syngas). Different fuels produce different compositions of syngas, but in general, the range of concentrations are as follows: CO (30-60%), H_2 (25-30%), CH_4 (0-5%), CO_2 (5-15%), and smaller varying amounts of H_2S and water vapor.[45] In IGCC power plants, Selexol is used to remove both CO_2 and H_2S from the gas stream before combustion takes place. A water-gas shift reactor (WGSR) is used to reduce CO emissions through conversion to CO_2. A GE quench gasifier is considered for the production of the syngas.

BECCS is studied under a near-term and long-term focus. The near-term scenario is based on the Billion Tonne Report's prediction on biomass production in the U.S. in 2020.[46] All

the power plants in this near-term focus are modeled as IGCC power plants running on non-pelletized fuel. This is because the infrastructure required for pelletization will not be available in 2020, and IGCC power plants are the only type of plants that can run on non-pelletized feed. IGCC power plants were simulated in 2020 to determine the current potential of BECCS and the effects of pelletization on the cost of BECCS. The long-term scenarios are divided into three sets of simulations: IGCC pelletized 2040, IGCC non-pelletized 2040, and PC pelletized 2040. In all simulation sets, the cost of BECCS is evaluated at increasing levels of biomass utilization. The fuel costs used in this study include the costs of growing, harvesting, pretreating, and transporting the biomass feed. The supply chain emissions of these processes have been considered as well.

The near-term 2020 scenario uses up to 206 million tonnes per year of biomass and captures roughly 181 million tonnes of CO_2 from the atmosphere annually in the U.S. The near-term scenario uses a combination of corn stover, hard wood residues, and whole trees, soft wood residues and whole trees, sorghum stubble, wheat straw, oat straw, and barley straw. Electricity is generated at costs that range between $130 and $180 per MWh after CO_2 capture, transport and storage. The CO_2 avoidance cost, which considers the increase in energy demand of CO_2 capture, transport and storage, ranges between $62 and $137 per tonne of CO_2. The long-term 2040 scenario uses up to 740 million tonnes of biomass and can sequester up to 737 million tonnes of atmospheric CO_2 per year. The long-term scenarios use a combination of the following biomass feedstocks: barley straw, corn stover, hardwood residues and whole trees, softwood residues and whole trees, miscanthus, oats straw, pine, poplar, softwood, sorghum, switchgrass, wheat straw, and willow. A major

difference in the feedstock from 2020 to 2040 is the presence of high energy density feedstocks like miscanthus and switchgrass.

Pelletization is integral in lowering the costs of BECCS. This is because pelletization helps increase the volumetric energy density of biomass by decreasing the water content of the fuel. Pretreatment also helps reduce pellet susceptibility to biological and thermal degradation. Dry, untreated pellets have been shown to self-combust if stored over long periods of time. The costs, energy penalties, and supply chain emissions of the pretreatment-pelletization process were evaluated by dividing the process into five main stages: grinding, drying, densifying, handling, and storage.[45] The Billion Tonne Report estimates that, for all feedstocks, grinding and drying are the most energy intensive processes.[46]

The economic potential of BECCS was evaluated at increasing levels of biomass utilization. The Biomass, Infrastructure, Logistics, and Transportation (BILT) model uses the cheapest, most energy dense fuels at the beginning, thus we predict increasing costs of BECCS with utilization. The cost of BECCS was evaluated using two approaches. The first approach involves using the well-known CO_2 Avoidance Cost (CAC) metric.[47] CAC relates the change in levelized cost of electricity (LCOE, in $/MWh) with CCS implementation to the change in emissions intensity (E, in tonnes CO_2/MWh) with CCS implementation. The second approach involves looking at the revenue required to break even and the net MWh produced to determine the break even cost of CCS. This approach can consider electricity sales revenues and potentially avoided CO_2 emissions by forgoing a coal power plant. Forgone coal emissions were considered to illustrate the cost of CCS on preexisting power plants.

Sensitivity analyses were performed to determine operating parameters that could most influence the performance of PC and IGCC power plants. Boiler efficiency, CO_2 compression energy requirement, and the solvent regeneration energy requirement are significant bottlenecks that BECCS PC power plants currently face. IGCC power plants can be optimized by finding optimal turbine inlet temperatures and Selexol regeneration conditions.

This work aims to calculate the economic potential of BECCS in the U.S. in 2020 and 2040 by playing close attention to power plant performance, potential supply chain emissions and costs, and potential biomass resource availability. BECCS and its value compared to other neutral emissions technology will be evaluated by comparing its costs to that of PC and NGCC power plants.

The cost calculations of BECCS presented in this thesis are a result of a collaborative effort between different projects. Oak Ridge Siting Analysis for power Generation Expansion (OR-Sage), developed at Oak Ridge National Laboratory, was used to determine potential sites for power plant locations. The Biofuel Infrastructure, Logistics, and Transportation Model (BILT) model, developed at Oak Ridge National Laboratory, was used to characterize the fuel blend going to each power plant and calculate optimal power plant sizing and supply chain costs and emissions related. The performance and economics of potential BECCS power plants and the application of different carbon accounting equations are presented in this thesis.

2. METHODS

Potential power plant locations were determined using OR-Sage. OR-Sage determines potential power plant locations in the U.S. capable of participating in BECCS based on several criteria including availability of water, availability of saline aquifers for CO_2 storage, population density, and demand for electricity. The Billion Tonne report also provides information regarding harvesting locations, crop yield, types of crops grown, and the as-delivered fuel cost (in $ per tonne) for the harvested fuel. BILT was used to develop the supply chain costs of transporting biofuels to the potential power plants and potential preprocessing costs, both before and after transportation. These three tools were used to determine the following inputs for the Integrated Environmental Control Model (IECM): transportation costs, fuel composition, fuel cost, fuel flowrates, power plant location and numbers, and power plant sizing.

IECM was used to simulate the performance and predict the costs of Integrated Gasification Combined Cycle (IGCC) and Pulverized Combustion (PC) power plants running on biomass. Fuel characteristics including cost of fuel, proximate and ultimate analyses of feed, and power plant sizing, locations, and numbers were used as input parameters. The power plants were modeled to include emissions control technologies for particulates, SOx, NOx, and CO_2. CO_2 capture was modeled using MEA as the carbon capture solvent, operating at 90% capture efficiency.

Power plant regions can affect the capital and operating costs of the power plant. There are six regions that the IECM uses to classify power plants, and they are presented in Table 1. Power plant location information, the biomass feed composition to the plant, the cost of

fuel, and the number of power plants and their respective sizing were determined by the BILT model.

Table 1. IECM Breakdown of U.S. States

Plant Location	States Included
U.S. Midwest	IA, IL, IN, KY, MI, MN, MO, ND, NE, OH, SD, WI, WV
U.S. Northeast	CT, DE, MA, MD, ME, NJ, NY, PA, VT
U.S. Northwest	ID, MT, OR, WA, WY
U.S. South Central	AR, KS, LA, OK, TX
U.S. Southeast	AL, FL, GA, MS, NC, SC, TN, VA
U.S. Southwest	AZ, CA, CO, NM, NV, UT

2.1 IECM Pulverized Combustion Modeling

PC power plants were modeled to include the following emissions controls technologies: SCR for NOx control, ESP for particulates capture, wet FGD for SOx capture, and amines for CO_2 capture. To model PC power plants, there are six main sections of the plant that require sizing and input information: overall plant, fuel, base plant, NOx control, SO_2 control, CO_2 capture and storage. The detailed setup of PC power plants can be found in Appendix B.

2.1.1 Overall Plant

The overall plant requires sizing for variables like yearly operating hours (7889 hr/yr), ambient air temperature and pressure (18.89°C, 0.1014 MPa), and humidity (50%). The overall plant also requires sizing information for the construction time (3 yr) and lifetime of the power plant (30 yr). Depending on the region selected, the capital cost multipliers for the overall plant (i.e., for construction equipment, materials, and labor) can vary. To be consistent, all power plants simulated in this study have identical ‘Overall Plant’ setups.

For simplicity, all power plants were modelled to run for 90% of available hours in a year, and it should be noted that this represents a best case scenario. Identical values for temperature, pressure, and humidity were used for simplicity.

2.1.2 Fuel

The IECM requires the following input parameters for the fuel used in PC power plants: higher heating value (kJ/kg), carbon (wt%), hydrogen (wt%), oxygen (wt%), chlorine (wt%), sulfur (wt%), nitrogen (wt%), ash (wt%), moisture (wt%), and cost ($/tonne). The compositions of all the pelletized fuel used can be found in Table 2. The IECM also requires information regarding the composition of the ash, including chemicals like: SiO_2, Al_2O_3, Fe_2O_3, CaO, MgO, Na_2O, K_2O, TiO_2, P_2O_5, SO_3, MnO_2. The proximate analyses of the fuels presented in Tables 2 and 3 were determined by taking weighted averages of three different biomass samples processed by Phyllis.nl, a database for physico-chemical composition of various biomass feedstock. Fuel costs used as IECM inputs take into account pretreatment, harvesting, production, and transportation.

Table 2. Pelletized Fuel Composition Information

Component	H_2O (%)	Ash (%)	C (%)	H (%)	N (%)	S (%)	O (%)	Cl (ppm)	LHV (MJ/kg)	HHV (kJ/kg)
Barley Straw	10	4.5	41.9	5	0.5	0.1	37.5	0	15.3	16.8
Corn Stover	10	5.4	41.1	5.1	0.6	0.1	37.3	0.3	15.1	16.6
Hardwood	10	1.4	47.1	5.6	0.2	0	35.8	0	18.1	19.9
Miscanthus	9	6.6	43	5.3	0.6	0.1	35.3	0	15.3	16.9
Mixedwood	10	2.2	47.1	5.5	0.4	0.1	34.8	0.1	17.8	19.6
Oats Straw	10	6.2	42.3	4.8	0.5	0.1	37	0	15.4	16.9
Pine	10	3.6	46.8	5.1	0.3	0	34.2	0	17.1	18.8
Poplar	10	1.6	43.9	5.4	0.2	0	38.8	0	16.3	17.9
Softwood	10	3.1	47.2	5.3	0.6	0.2	33.7	0.1	17.5	19.2
Sorghum	10	6.3	41.3	4.5	0.7	0	36.9	0	15	16.5
Switchgrass	9	6.6	43	5.3	0.6	0.1	35.3	0	15.3	16.9
Wheat Straw	10	5	41.4	5.1	1	0.1	36.8	0	15.9	17.5
Willow	10	1.4	44.6	5.5	0.5	0	38	0	16	17.6
*Appalachian Medium Sulfur	5.1	7.2	73.8	4.9	1.4	2.1	5.4	0	26.7	30.8

Note: Appalachian Medium Sulfur coal was used in PC power plant simulations to determine CAC.

Table 3. Pelletized Fuel Ash Composition Information

Component	SiO_2 (%)	Al_2O_3 (%)	Fe_2O_3 (%)	CaO (%)	MgO (%)	Na_2O (%)	K_2O (%)	P_2O_5 (%)	SO_3 (%)
Barley Straw	62.0	0.2	0.2	4.5	2.2	0.4	19.3	2.5	1.4
Corn Stover	54.0	2.0	0.0	8.7	6.1	0.2	20.7	8.7	0.0
Hardwood	11.1	0.1	3.3	64.5	1.2	8.9	0.2	0.0	2.0
Miscanthus	82.3	0.8	0.4	4.1	2.6	0.2	4.6	1.9	1.7
Mixedwood	5.6	1.5	3.8	50.8	3.5	6.0	8.6	0.9	6.6
Oats Straw	16.9	0.6	0.4	6.9	1.7	7.5	31.8	1.8	3.0
Pine	39.0	14.0	3.0	25.5	6.5	1.3	6.0	0.0	0.3
Poplar	0.9	0.3	0.5	44.0	4.3	0.2	20.1	0.2	4.0
Softwood	0.0	2.8	4.2	37.1	5.9	3.2	17.0	1.9	11.2
Sorghum	46.0	0.5	0.4	8.1	4.0	0.5	28.6	6.2	3.6
Switchgrass	82.3	0.8	0.4	4.1	2.6	0.2	4.6	1.9	1.7
Wheat Straw	37.1	2.2	0.8	4.9	2.6	9.7	21.7	2.0	4.4
Willow	2.8	0.1	0.4	36.5	1.5	2.0	19.9	12.9	1.9
*Appalachian Medium Sulfur	54.5	17.3	4.5	10.7	2.4	1.5	1.1	0.3	7.0

Note: Appalachian Medium Sulfur coal was used in PC power plant simulations to determine CAC

2.1.3 Base Plant

In PC power plants, the base plant has the following units, all of which require sizing: boiler, air preheater, steam cycle, and furnace.

The boiler was modeled to have a thermal efficiency of 87.5% and was set to tangential combustion. In general, based on the orientation, there are three different types of furnaces: horizontal (opposed jets or front firing), down shot, and corner firing (tangential).[48] Power plants were sized to the following gross MW based on the output of the BILT model: 50MW, 100MW, 150MW, 200MW, 250MW, 300MW, 350MW, 400MW, 450MW, 500MW, 1000MW, and 1500MW. 20% excess air was used in the combustion process. The gas temperature leaving the economizer was set to 371°C and the gas temperature exiting the preheater was set to 149°C.

2.1.4 NOx Emissions Control

NOx emissions are controlled both in-furnace and on the hot-side. In the furnace, NOx emissions are controlled by using low nitrous burners (LNB). LNB operate in two stages. The first stage involves fuel combustion in an oxygen-starved, fuel rich environment. This is where NOx is formed. The second stage involves reacting NOx with hydrocarbons in a reducing atmosphere. The LNBs are simulated to remove 44% of incoming NOx.

Outside the furnace, NOx emissions are captured through selective catalytic reduction (SCR), where 50% of incoming NOx emissions are captured. A catalyst price of $\$6000/m^3$ was assumed.[49]

2.1.5 Total Suspended Particle (TSP) Control

TSP control in the IECM is conducted through electrostatic precipitation (ESP). ESP contains a series of parallel plates with electrodes carrying voltage of opposite polarity. Particles in the flue gas are attracted to the plates. The plates are struck at an interval and the falling particles are collected in a hopper below.

The ESP used in the PC plants operated at a particulate removal efficiency of 99%, with 682 m^2/Macmm plates at 30.48 cm separation. A schematic of the ESP process can be found in Figure 6.

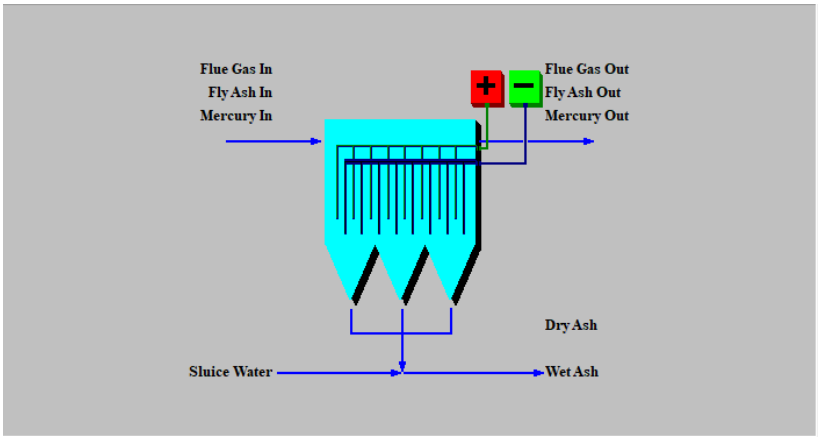

Figure 6: Schematic of ESP used in TSP control in PC power plants.

2.1.6 SO_2 Emissions Control

SO_2 emissions were captured using limestone in wet flue gas desulfurization (FGD). The scrubber efficiency was set to remove 98% of incoming SO_2, which is sufficient for all carbon capture technologies modelled in this thesis. A regent stoichiometry of 1.03 mol Ca per mol S removed was used, with a reagent purity of 92.4%. The temperature of the flue gas entering the FGD was set to 62.3°C. 90% of formed $CaSO_3$ was set to oxidize to $CaSO_4$. A figure illustrating the SO_2 removal can be found in Figure 7.

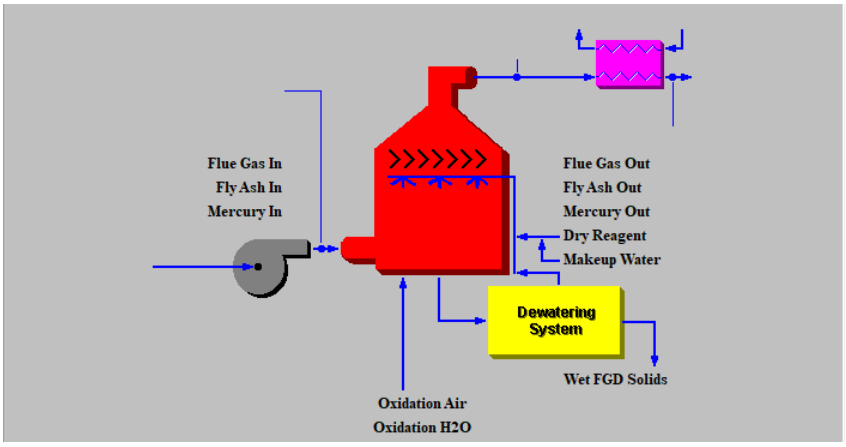

Figure 7: Schematic of wet FGD used in PC power plants.

2.1.7 CO_2 Capture, Transport, and Storage

All PC power plants were modeled to chemically absorb 90% of incoming CO_2 with 30 wt% MEA. A 6-stage compressor was used along with a direct contact cooler. A schematic of the CO_2 capture unit in PC power plants can be found in Figure 8.

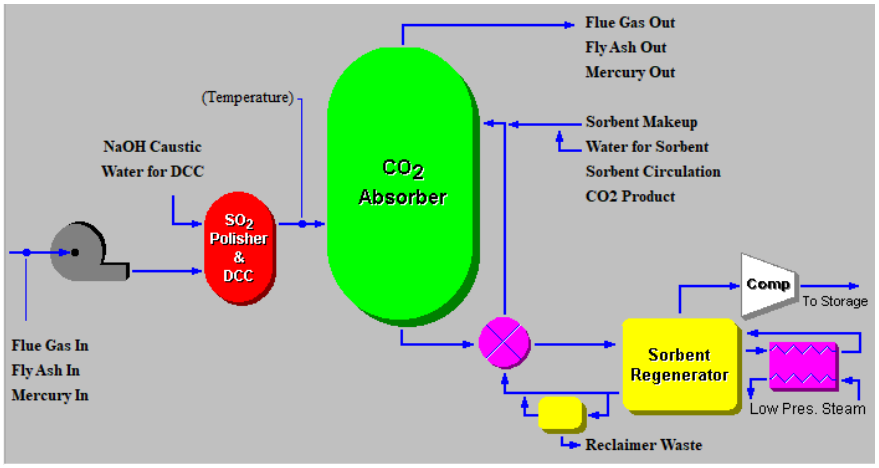

Figure 8: Schematic of CO_2 capture system using MEA in PC power plants.

The lean CO_2 loading of the solvent was 0.2 mol CO_2 per mol sorbent, with 2.25 kg/tonne CO_2 solvent losses, and 0.2 kg/tonne CO_2 of solvent recovered. The regeneration heat requirement of the solution was assumed to be 5024 kJ per kg CO_2, with a heat to electricity efficiency of 19.7%.

The captured CO_2 is pressurized to 13.79 MPa and is transported via pipelines to geological storage sites. The pipelines are 100 km in length, with a minimum outlet pressure of 10.3 MPa. CO_2 storage was modeled using a reservoir with the following characteristics found in Table 4. The storage performance was modeled after Law and Bachu.[50]

Table 4. CO_2 Storage Site Characteristics

Depth (m)	1219
Thickness (m)	304.8
Reservoir Horizontal Permeability (mD)	100
Reservoir Porosity (%)	120
Storage Coefficient (%)	5.8
Reservoir Surface Temperature (°C)	45.44
Geographical Area for CO2 storage (km^2)	7.019×10^4

2.2 IECM Integrated Gasification Combined Cycle Modeling

IGCC power plants were modeled to include the following emissions controls technologies: sulfur and CO_2 removal using Selexol.

IGCC power plant simulation required information for the following sections: overall plant, fuel, air separation unit, gasifier area, sulfur removal, power block, and CCS. More detailed information regarding IGCC modeling can be found in Appendix C.

2.2.1 Overall Plant

The same conditions used in PC power plants in Section 2.1 were used in IGCC simulations.

2.2.2 Fuel

The IECM requires the following input parameters for the fuel used in PC: higher heating value (kJ per kg), carbon (wt%), hydrogen (wt%), oxygen (wt%), chlorine (wt%), sulfur (wt%), nitrogen (wt%), ash (wt%), moisture (wt%), and cost ($ per tonne). The compositions of the pelletized and non-pelletized fuel used can be found in Tables 2 and 5, respectively. The IECM also requires information regarding the syngas produced by the gasification of the different feed. The following compounds were required: CO, H_2, CH_4, C_2H_6, C_3H_8, H_2S, COS, NH_3, HCl, CO_2, H_2O, N_2, and Ar. The compositions of the syngas produced from each fuel can be found in Table 6.

Table 5. Composition of Non-Pelletized Feedstocks Used in IGCC Simulations

Component	H_2O (%)	Ash (%)	C (%)	H (%)	N (%)	S (%)	O (%)	Cl (ppm)	LHV (MJ/kg)	HHV (MJ/kg)
Barley straw	10.0	4.5	41.9	5.0	0.5	0.1	37.5	5225.4	15.3	16.7
Corn stover	20.0	4.8	36.5	4.6	0.5	0.1	33.2	0.2	13.1	14.4
Hardwood	50.0	1.1	26.2	3.1	0.1	0.0	19.9	25.0	9.0	10.8
Mixedwood	50.0	1.4	26.2	3.0	0.2	0.1	19.3	25.0	8.8	10.7
Oats straw	10.0	6.2	42.3	4.8	0.5	0.1	37.0	7155.0	15.4	16.7
Pine	40.0	2.4	31.2	3.4	0.2	0.0	22.8	0.0	10.7	12.3
Poplar	40.0	1.1	29.3	3.6	0.2	0.0	25.9	0.0	10.0	11.5
Softwood	50.0	1.7	26.2	3.0	0.3	0.1	18.7	0.0	8.6	10.5
Sorghum	20.0	5.6	36.7	4.0	0.6	0.0	32.8	2293.3	13.1	14.5
Switchgrass	15.0	6.1	40.2	4.9	0.6	0.1	32.9	0.2	14.2	16.3
Miscanthus	15.0	6.1	40.2	4.9	0.6	0.1	32.9	0.2	14.2	16.3
Wheat straw	10.0	5.0	41.4	5.1	1.0	0.1	36.8	3045.3	15.9	17.3
Willow	50.0	0.8	24.8	3.1	0.3	0.0	21.1	7.8	9.7	10.0

Table 6. Composition of Syngas Produced from Gasification of Feedstocks

Component	C_2H_6	C_3H_8	CH_4	CO	CO_2	H_2	H_2O	H_2S	HCl	N_2
Barley Straw	0.0	0.0	0.3	21.8	0.4	18.4	0.9	0.0	0.1	58.0
Corn stover	0.0	0.2	6.4	11.4	10.0	11.3	0.0	0.0	0.0	58.0
Hardwood	0.0	0.0	1.3	19.7	11.9	9.1	0.0	0.0	0.0	57.3
MixedWood	0.0	0.0	3.9	10.8	9.8	17.5	0.0	0.0	0.0	58.0
Oats Straw	0.0	0.0	3.6	11.7	7.1	19.2	0.0	0.0	0.0	58.0
Pine	1.2	0.0	8.5	14.2	8.6	8.7	0.0	0.0	0.0	58.0
Poplar	0.0	0.0	4.8	14.8	14.2	8.2	0.0	0.0	0.0	58.0
Softwood	0.0	0.0	3.6	9.7	8.7	19.1	0.0	0.0	0.0	58.0
Sorghum	0.0	0.0	5.9	3.6	2.4	29.2	0.0	0.0	0.0	58.0
Switchgrass	0.4	0.0	4.1	17.6	14.1	5.2	0.0	0.0	0.0	58.6
Miscanthus	0.0	0.0	3.9	10.8	9.8	17.5	0.0	0.0	0.0	58.0
Wheat Straw	0.0	0.3	6.9	12.2	9.2	10.7	0.0	0.0	0.0	58.0
Willow	0.1	0.0	1.5	27.5	3.8	8.3	0.0	0.0	0.0	56.0

2.2.3 Air Separation Unit

A schematic of the ASU used in IGCC power plants can be found in Figure 9. The ASU is modeled to produce an oxidant with 95 vol% O_2, 4.2 vol% Ar, and 0.8 vol% N_2, at a pressure of 4 MPa. The ASU consumes 265.7 kWh per tonne of oxidant produced.

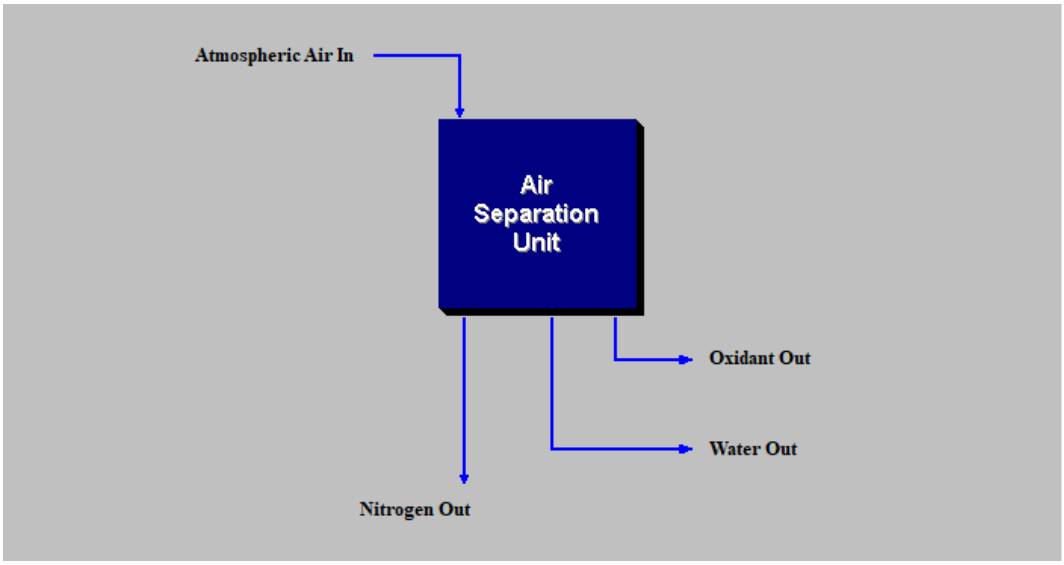

Figure 9: Schematic of ASU used in IGCC power plants.

2.2.4 Gasifier Area

A gasifier was used to convert the incoming biomass feed to syngas through reaction with the oxidant produced in the ASU. This gasification reaction was conducted at 1343°C and 4.24 MPa, with a steam input of 0.44 mol H_2O per mol C, and oxygen input of 0.45 mol O_2 per mol C. A schematic of the gasification can be found in Figure 10.

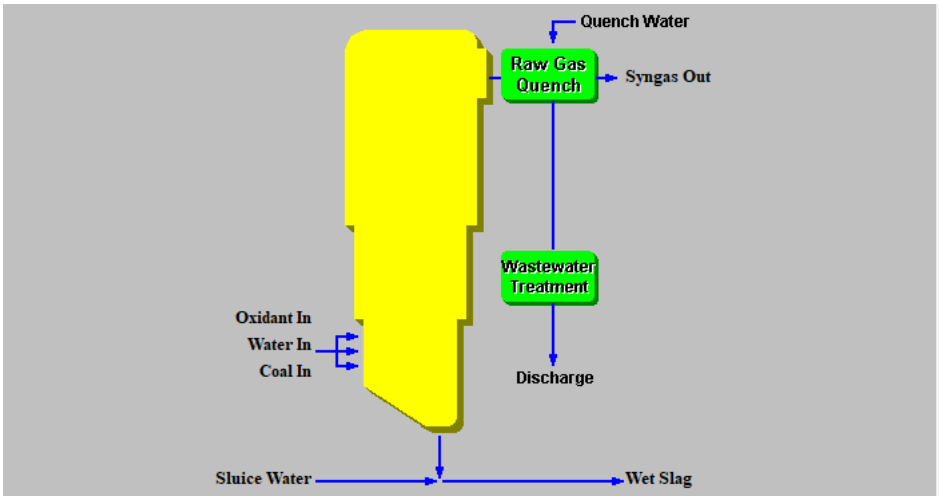

Figure 10: Schematic of gasifier used to produce syngas in IGCC power plants.

2.2.5 Sulfur Removal

SO_2 emissions from IGCC power plants are controlled by removing sulfurous species before combustion. The syngas is assumed to have been removed of particulate matter before entering the sulfur removal system. Selexol is used to separate H_2S and COS in the stream before being sent to a Claus plant and a Beavon-Stretford plant for tail gas treatment and sulfur recovery. 95% of incoming H_2S is absorbed by the Selexol solvent. COS is present in minute quantities, and 30% of incoming COS is captured. A hydrolyzer is used to convert COS to H_2S before the Selexol treatment. Figure 11 illustrates the setup of the sulfur removal system.

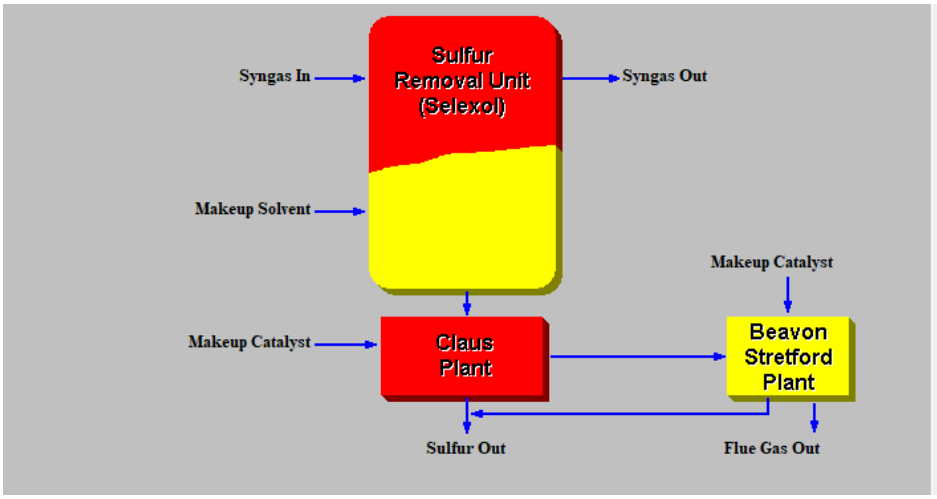

Figure 11: Schematic of sulfur recovery system in IGCC power plants.

2.2.6 Power Block

The power block includes all the equipment necessary to convert the potential and kinetic energy of syngas fuels into steam and electricity. The gas turbine needs specifications regarding the temperatures, pressures, and volumetric flowrates of air entering the compressor, syngas entering the combustor, and flue gas exiting the gas turbine. A schematic illustrating the power block can be found in Figure 12. The power block requires sizing the gas turbine, air compressor, the combustor, and heat recovery system. The gas turbine performance was modeled using a GE 7FB gas turbine, with an inlet temperature of 1371°C, fuel moisture content of 20%, and turbine efficiency of 85%. The combustor inlet pressure is set to 1.875 MPa.

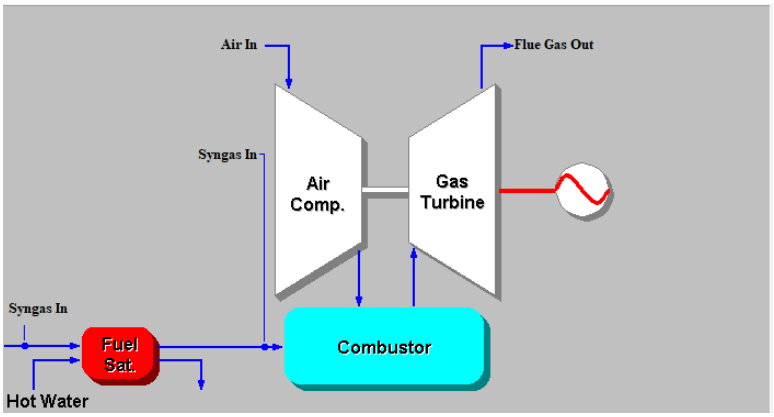

Figure 12: Schematic of the IGCC power block.

2.2.7 CO_2 Capture, Transport, and Storage

IGCC uses Selexol to absorb 90% of incoming CO_2 before combustion. The product CO_2 is compressed to 13.79 MPa and then injected in saline aquifers 100 miles away from the plant.

A water-gas shift reactor is used to convert CO and COS to CO_2 and H_2S, respectively, by reaction with water vapor. Schematics illustrating the water-gas shift reactor and CO_2 absorber are presented in Figures 13 and 14. The CO_2 transport and storage for IGCC plants are performed under identical conditions to PC plants mentioned in Section 2.1.7.

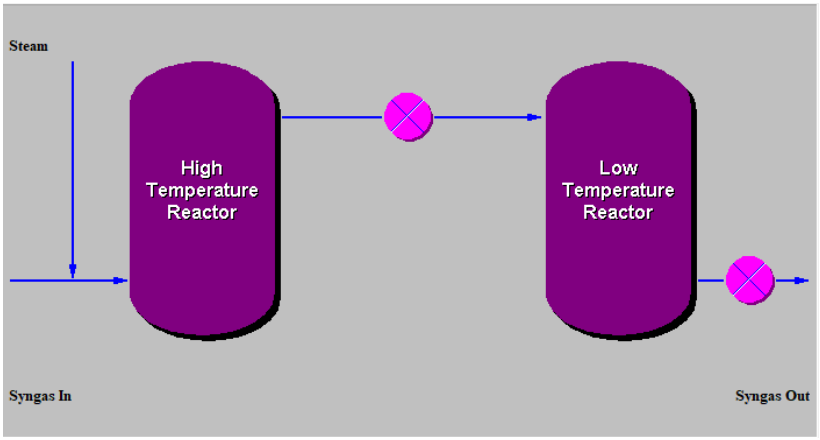

Figure 13: Water-gas shift reactor used to convert CO and COS to CO_2 and H_2S before contact with Selexol.

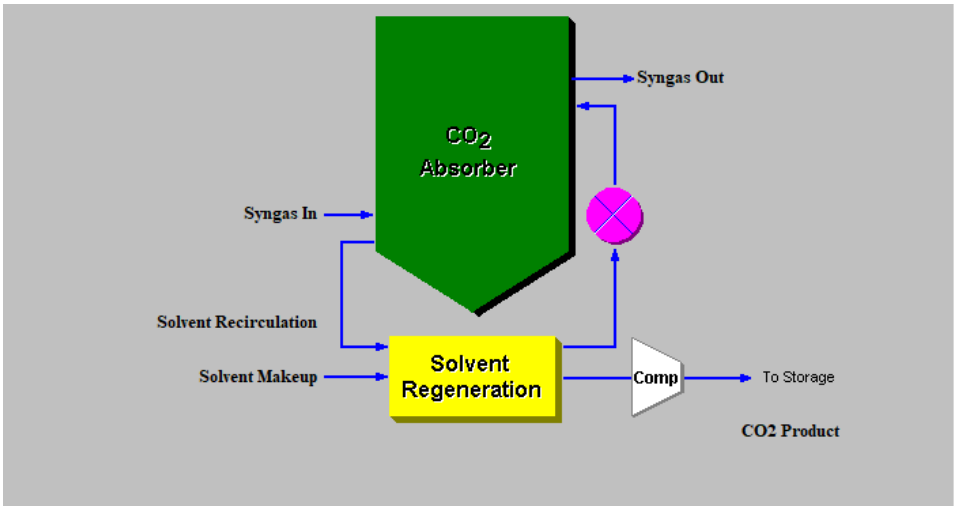

Figure 14: CO_2 absorber used to capture incoming CO_2 in IGCC power plants.

2.3 IECM Natural Gas Combined Cycle Modeling

NGCC power plants were simulated with and without CCS in order to calculate the reference case emissions intensity (tonne CO_2 per MWh) and cost of electricity ($ per MWh) for the CAC calculations.

NGCC power plant simulation required information for the following sections: overall plant, flue, power block, and CCS. More detailed information regarding the turbine sizing of NGCC plants can be found in the supplemental information shown in Appendix C.

2.3.1 Overall Plant

The same conditions used in PC power plants discussed in Section 2.1 were used in NGCC simulations.

2.3.2 Fuel

Natural gas with the composition in Table 7 was used in NGCC simulations.

Table 7. Natural Gas Composition Used in NGCC Simulations

Component	Value
CH_4 (vol%)	93.1
C_2H_6 (vol%)	3.2
C_3H_8 (vol%)	1.1
CO_2 (vol%)	1.0
O_2 (vol%)	0
N_2 (vol%)	1.6
H_2S (vol%)	0
Higher Heating Value (kJ/kg)	$5.229*10^4$
Natural Gas Density (kg/m^3)	0.73
Natural Gas Cost ($/mscm)	260.2

2.3.3 Power Block

Simulating the power block requires information to size the gas turbine, air compressor, combustor, and the steam cycle performance. The GE 7FB gas turbine was modeled with 1-5 turbines. The turbine inlet temperature was set to 1371°C with a turbine back pressure of $1.38x10^{-2}$ MPa. In the air compressor, a pressure ratio of 18.5 (outlet/inlet) was used, with an adiabatic compressor efficiency of 87.5%. More detailed information for the power block can be found in the supplemental information shown in Appendix C. A schematic of the power block can be found in Figure 15.

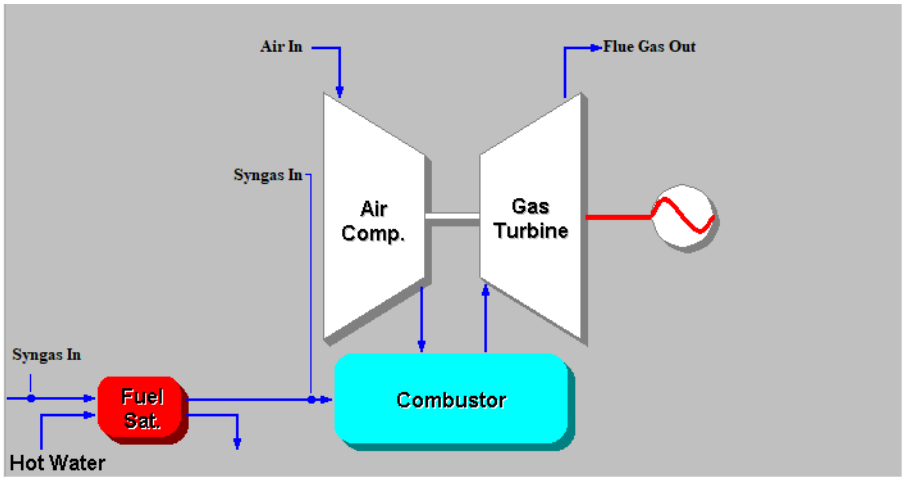

Figure 15: Schematic of NGCC power block.

2.3.4 CO_2 Capture, Transport, and Storage

The absorber was modeled to remove 90% of incoming CO_2 using 30 wt% MEA solution. The lean CO_2 loading of the solvent was 0.2 mol CO_2 per mol sorbent, with 2.25 kg per tonne CO_2 solvent losses, and 0.2 kg solvent per tonne CO_2. The regeneration heat requirement of the solution was assumed to be 5024 kJ per kg CO_2, with a heat to electricity efficiency of 19.7%. A schematic of the amine capture mechanism using MEA in NGCC plants can be found in Figure 16. The captured CO_2 is pressurized to 13.79 MPa and is transported via pipelines to geological storage sites. The pipelines are 100 km in length, with a minimum outlet pressure of 10.3MPa. CO_2 storage was modeled using a reservoir with the following characteristics found in Table 8. The storage performance was modeled after Law and Bachu.[50]

The CCS conditions in NGCC power plants are identical to those described in Section 2.3.7.

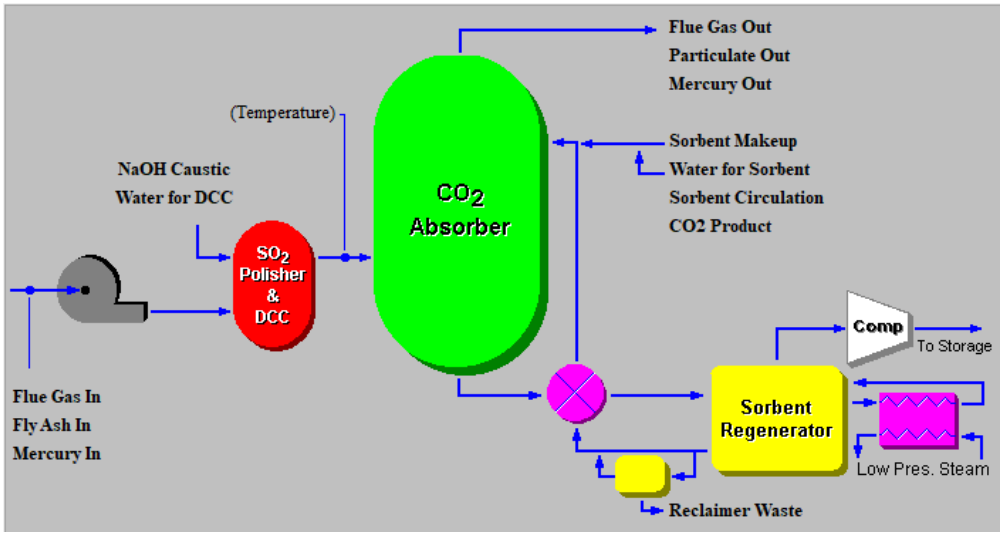

Figure 16: MEA CO_2 absorber used in NGCC power plants.

Table 8. CO_2 Storage Site Characteristics

Depth (m)	1219
Thickness (m)	304.8
Reservoir Horizontal Permeability (mD)	100
Reservoir Porosity (%)	120
Storage Coefficient (%)	5.8
Reservoir Surface Temperature (°C)	45.44
Geographical Area for CO_2 storage (km^2)	$7.019*10^4$

2.4 Potential Sites

OR-Sage was used to identify potential locations for BECCS power plants based on factors like proximity to saline aquifers, land suitable for power plant construction, and exclusion of areas sensitive to hazards. Additional criteria used in screening potential sites can be found in Table 9. Figure 17 illustrates potential sites in the US that have passed the additional screening.

Table 9. Additional Criteria Used in the Selection of Potential Power plant Sites[26]

	Exclusion Value
Population Density	>195 people/mil^2
Wetlands/Open Water	No
Protected Land	No
Slope	>12% gradient
Landslide Hazard	No
100-year floodplain	No
Cooling water make-up within 20 miles	473000 L/min
U.S. Geological formations	Saline basins
U.S. EPA non-attainment areas	No

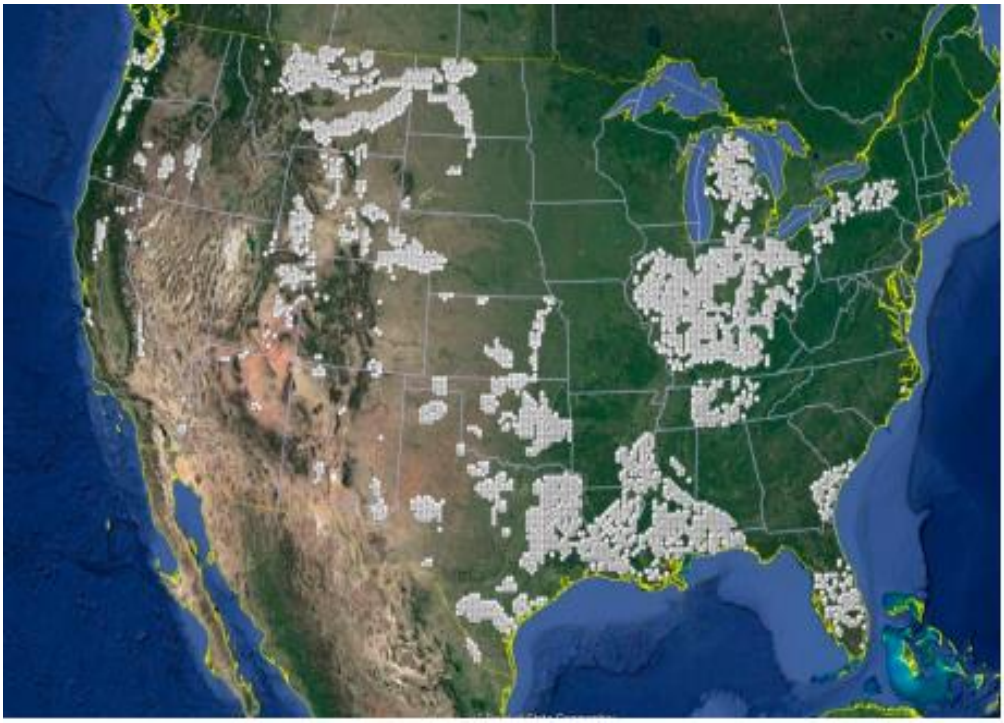

Figure 17: Potential power plant sites based on criteria mentioned in Table 9.[26]

2.5 CO_2 Avoidance Cost and Cost of CCS Equations

2.5.1 CAC Calculations

The CO_2 Avoidance Cost (CAC) can be described by the following equation:[47]

$$\mathrm{CAC} = \frac{\mathrm{LCOE_{CCS}} - \mathrm{LCOE_{Base}}}{\mathrm{E_{Base}} - \mathrm{E_{CCS}}} \quad (9)$$

where LCOE is the levelized cost of electricity, i.e., the revenue required to break even (in $ per MWh) and E is the emissions intensity of the power plant in (tonnes CO_2 per MWh). CCS refers to the power plant scenario with carbon capture and storage (BECCS), and the Base refers to the reference case power plants. In this study, there are two sets of CAC

values calculated, one to compare BECCS to reference cases with CCS, and another to compare BECCS to reference cases without CCS. The reference case power plants include NGCC with and without CCS, and PC power plants running on coal with and without CCS. IECM calculates the 'Revenue Required to Break Even ($ per MWh),' which summarizes the total annual cost of running a power plant with respect to its total MWh output. A weighted LCOE was calculated using the reported revenues required to break even, number of power plants, and capacity per power plant for each BECCS scenario. Emissions intensities are also an output of the IECM program, and similar weighted averages were calculated for both BECCS and reference cases.

2.5.2 Cost of CCS Equations

The Cost of CO_2 Capture (Cost of CCS) equations can be described by the following equations:

$$\mathrm{CCS}_1 = \mathrm{LCOE}\left(\frac{\$}{\mathrm{MWh}}\right) \mathrm{x} \frac{\mathrm{MWh_{net}}}{\mathrm{yr}} \mathrm{x} \frac{\mathrm{yr}}{\mathrm{tonne\ CO_{2_{emitted}}}} \quad (10)$$

$$\mathrm{CCS}_2 = \left[\mathrm{LCOE}\left(\frac{\$}{\mathrm{MWh}}\right) - \mathrm{wholsale\ rate}\left(\frac{\$}{\mathrm{MWh}}\right)\right] \mathrm{x} \frac{\mathrm{MWh_{net}}}{\mathrm{yr}} \mathrm{x} \frac{\mathrm{yr}}{\mathrm{tonne\ CO_{2_{emitted}}}} \quad (11)$$

$$\mathrm{CCS}_3 = \left[\mathrm{LCOE}\left(\frac{\$}{\mathrm{MWh}}\right) - \mathrm{wholsale\ rate}\left(\frac{\$}{\mathrm{MWh}}\right)\right] \mathrm{x} \frac{\mathrm{MWh_{net}}}{\mathrm{yr}} \mathrm{x} \frac{\mathrm{yr}}{\mathrm{tCO_{2_{emitted}}} - \mathrm{tCO_{2_{avoided}}}} \quad (12)$$

Here, the cost of electricity refers to the IECM output "revenue required to break even". Based on a 90% capacity factor, which is the fraction of operating hours per year, and the MW_{net} output from the IECM, annual MWh production can be calculated. The wholesale rate was determined by taking the average wholesale rate in the specified region. Figure 18 illustrates the stratification of U.S. wholesale markets. The tonnes of CO_2 avoided was calculated by determining the tonnes of CO_2 emissions that are forgone by not using a coal

power plant of the same capacity. This calculation was conducted by simulating a PC power plant of the same capacity on the IECM without CCS. CCS_3 was used to determine the best-case cost of BECCS where a preexisting coal power plant is retrofitted to handle biomass feed and can generate revenue from electricity sales.

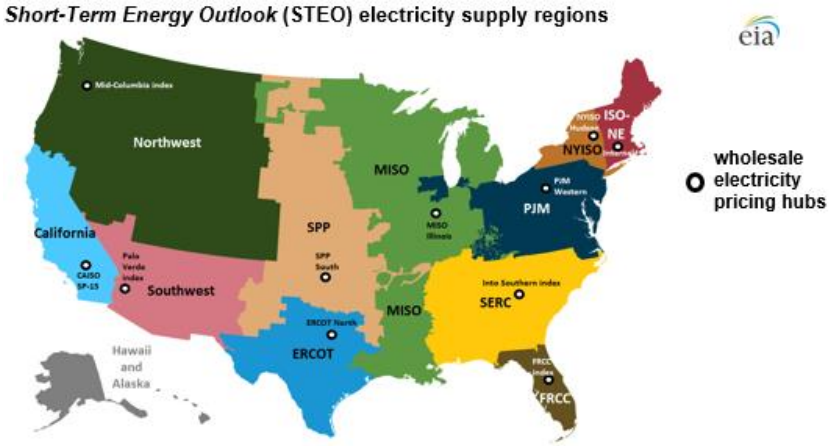

Figure 18: USA wholesale electricity regions.[51]

2.6 Sensitivity Analyses

A single-parameter linear sensitivity analysis was conducted to determine influential parameters in IGCC and PC power plant performance. Sensitivity analyses were conducted by changing one input parameter by ± 10% from its base value and measuring the change in an output variable, the revenue required to break even. Revenue required to break even was chosen as the primary output variable since it summarizes the total cost of the power plant and the total power it can produce, thus telling us the breakeven cost of running the power plant in $ per MWh. Sensitivity was calculated using Equation 13. The baseline values of all parameters used in the sensitivity analysis can be found in Appendices D and E.

$$\text{Sensitivity} = \frac{\text{Revenue}_{\text{Base}} - \text{Revenue}_{\text{Sensitivity}}}{\text{Revenue}_{\text{Base}}} \text{ x } 100 \quad (13)$$

3. RESULTS AND DISCUSSION

3.1 Levelized Cost of Electricity (LCOE) Estimates

The scenario-averaged levelized cost of electricity (LCOE), cost of CCS (Equations 10-12), and CO_2 avoidance cost (Equation 13) are presented in Figures 19, 21, and 22, respectively. These results are expressed as weighted averages with increasing levels of potential sequestrable CO_2 (10% to 90% in increments of 10%). All costs presented in this thesis are in terms of 2018 USD. IECM simulations indicate that PC power plants were greatly influenced by economy of scale, i.e., larger capacity power plants produce electricity at lower costs. IGCC power plants, however, do not show this economy of scale, and this can be explained by their power generating mechanism. IGCC power plants increase in size by adding turbines instead of increasing the capacity of the turbine. Thus, this results in increasing costs of electricity production with power plant size.

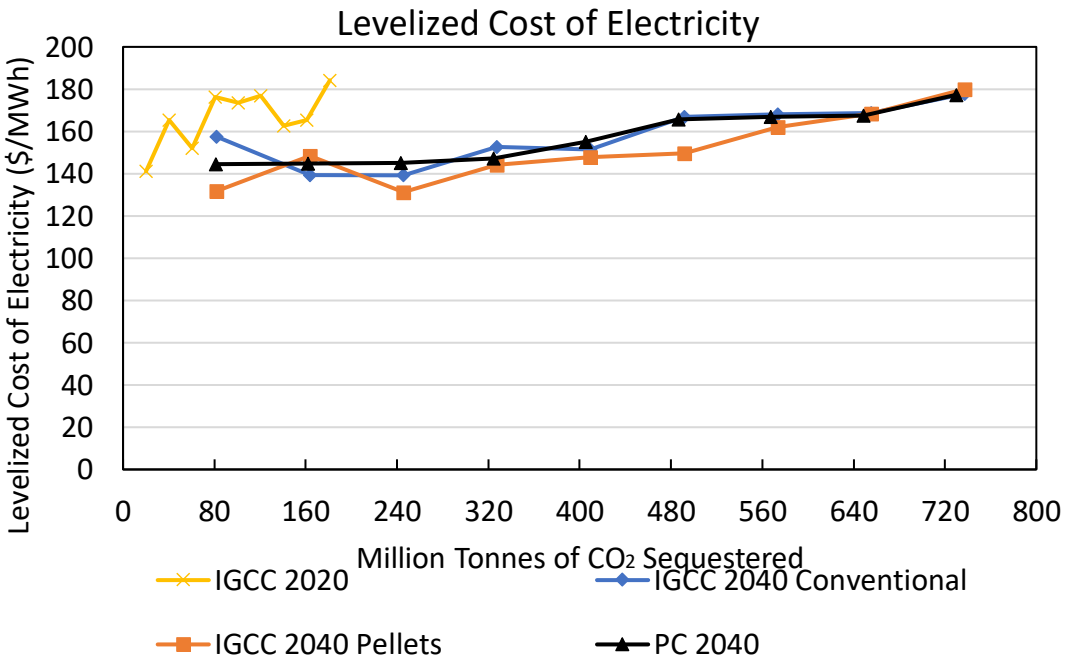

Figure 19: Levelized cost of electricity (LCOE) for the four BECCS scenarios.[26]

The LCOE generally increases with biomass utilization and percentage of potential CO_2 sequestered. The LCOE ranges between $140 and $180 per MWh in the 2020 scenario and between $130 to $180 per MWh in the 2040 scenario. According to EIA estimates, PC power plants without CCS produce electricity at costs of $36 to $68 per MWh.[52] This increase in cost can be attributed to the energy demand of the CCS process.

In all long-term scenarios, the energy intensity of the feedstock (in MJ per $) is seen to decrease with increasing levels of biomass utilized. This decrease in energy intensity of the fuel can be explained by the increase in fuel cost and decrease in energy density of fuel (in MJ per tonne) with increasing demand for BECCS. The energy density of the feedstock blend decreases with utilization since the BILT model predicts that it is more efficient to consume the high-density fuels first. In the IGCC 2020 case, however, due to the variance in feedstock availability and feedstock quality in the near term, the energy intensity of the fuel initially increases with increasing CO_2 sequestration levels, thus decreasing the cost of BECCS. The types of biomass available in 2020 and 2040 and the fuel intensity of the feed used in the four BECCS scenarios can be found in Figures 20 and 21.

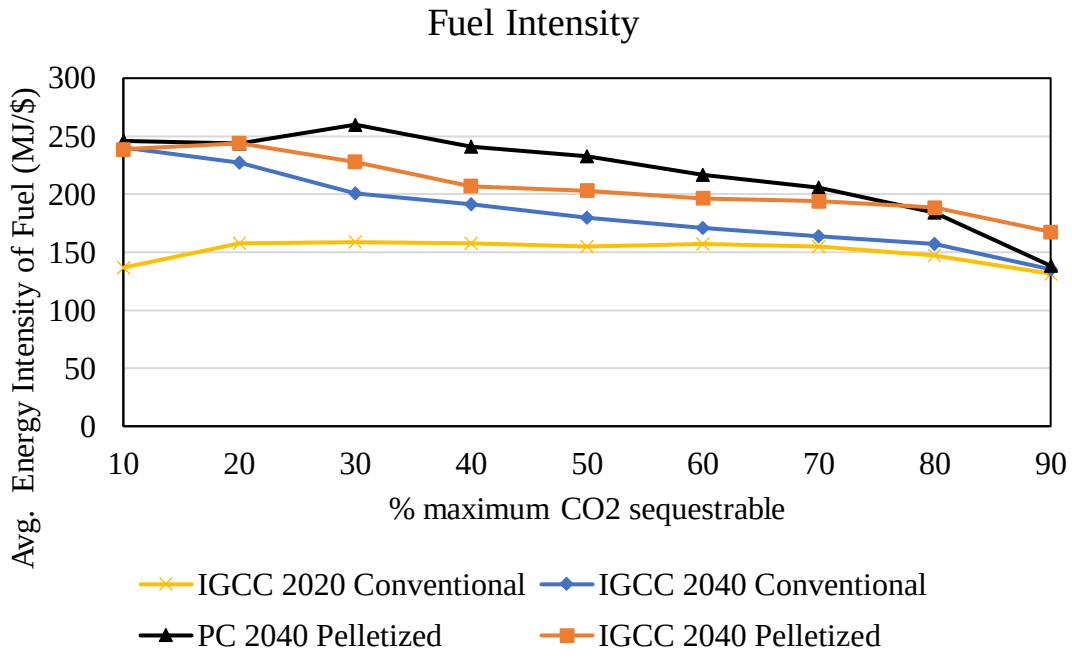

Figure 20: Average fuel intensity of feedstock (in MJ per $) used in the four BECCS scenarios.

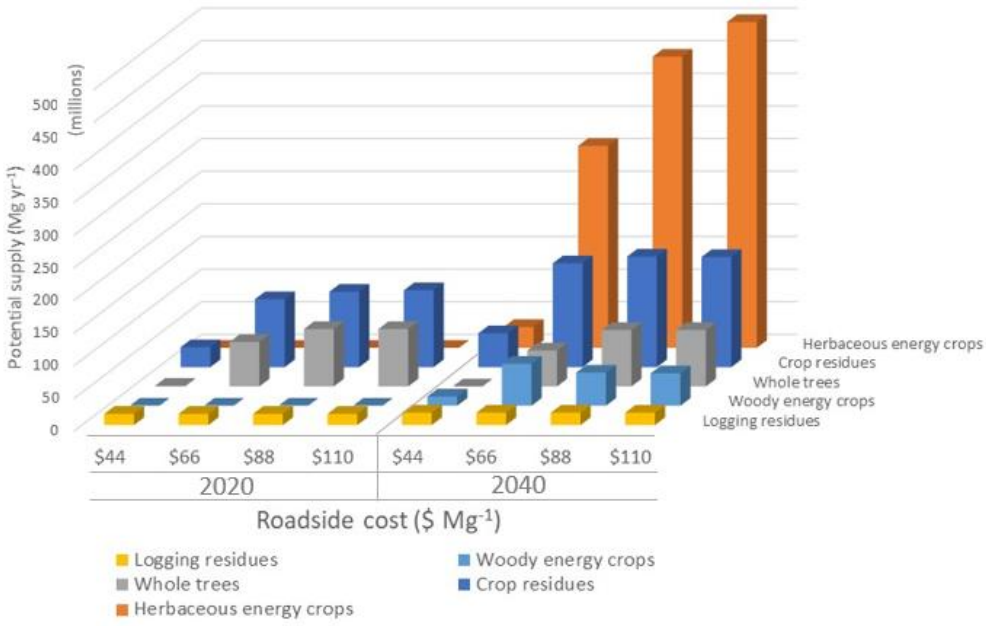

Figure 21: Potential biomass supply used in this thesis, by feedstock, roadside cost (including production and harvest but excluding transportation or processing), and year.[26]

3.2 CCS Accounting Equations (Equations 10-12)

Figure 22 illustrates the cost of CCS for the four BECCS scenarios using the three cost of CCS equations (Equations 10-12). In the three 2040 scenarios, the cost of CCS increases with increasing levels of potential CO_2 sequestered. Variability in the feedstock in the near term makes the cost of CCS decrease initially before increasing afterwards. In the 2040 scenarios, the cost of CCS is the lowest in the pelletized IGCC scenario. Both IGCC scenarios sequester CO_2 at lower costs than the PC setup. Pelletization was seen to help decrease the cost of CCS in IGCC power plants. The cost of CCS is analogous to the LCOE, except it represents the cost per tonne of CO_2 that is captured, transported, and stored. For CCS_1 (Equation 10), the cost of CCS ranged between \$88 and \$176 per tonne CO_2. CCS_2 (Equation 11) considers the revenue generated from wholesale of electricity, and ranges between \$62 and \$166 per tonne CO_2. CCS_3 (Equation 12) considers both the wholesale of electricity and the avoided emissions from not using coal, and ranges between \$35 and \$63 per tonne CO_2.

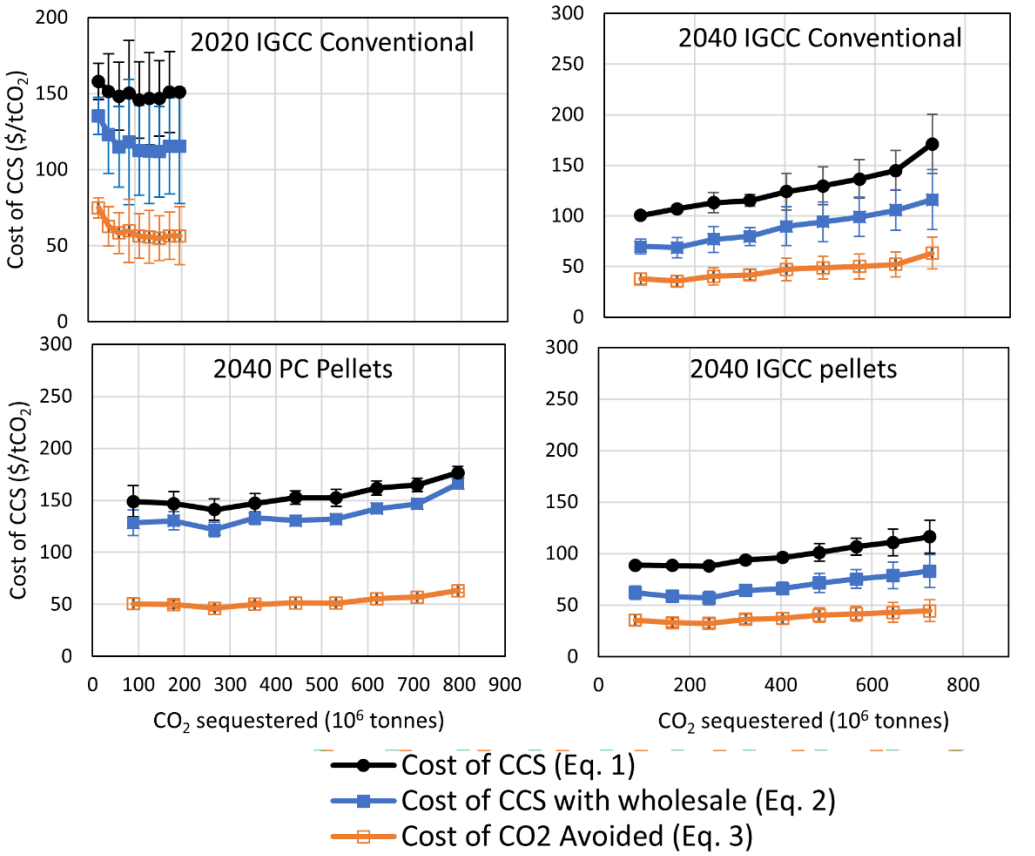

Figure 22: Scenario-average cost of CCS (in $ per tonne of CO_2 captured) for the four BECCS scenarios. CCS_1 (Equation 10) represents the cost of CCS, CCS_2 (Equation 11) represents the cost of CCS with the wholesale of electricity, and CCS_3 (Equation 12) represents the cost of CCS with the wholesale of electricity and avoided emissions from replacing coal power plants.[26]

3.3 CAC Calculations Using PC Power plants with Coal

A PC coal power plant powered by coal with the characteristics mentioned in Table 3 was used as a reference case in CAC calculations. The CAC ranges between $39 and $93 per tonne of CO_2 avoided when using a PC power plant reference case without CCS. The avoided emissions of other technologies can be found in Table 10. To determine the additional cost of CO_2 removal from the atmosphere, beyond flue gas treatment, a PC reference case with CCS was considered. This cost ranges between $29 and $142 per tonne avoided and is presented in Figure 23. This is competitive with the CAC of neutral emissions technologies. PC power plants were considered as reference cases for the CAC calculations as they are the most common type of power plant found in the U.S. [53]

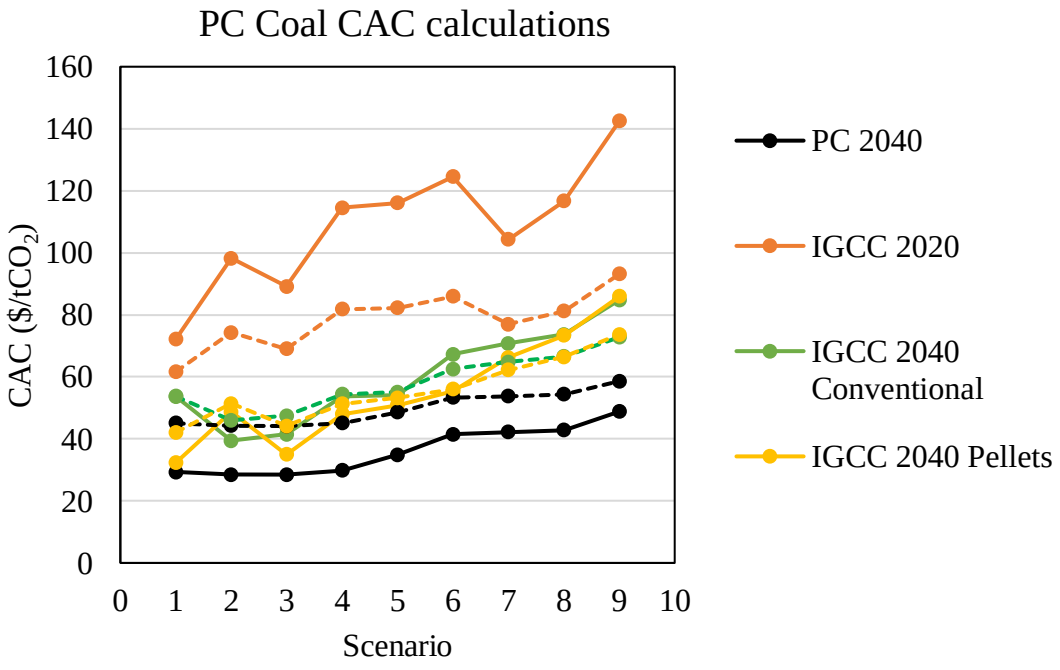

Figure 23: CO_2 avoidance cost (in $ per tonne of CO_2 avoided) using a PC power plant as a reference case. The dashed lines represent CAC costs using a reference case without CCS and the solid lines represent a reference case with CCS.

Table 10. Neutral Emissions Technologies and their Approximate CO_2 Avoidance Costs

Neutral Emissions Technology	Estimated Cost
Nuclear[54]	\$8 to \$28 per tonne of CO_2
Coal with CCS [54]	\$48 to \$109 per tonne of CO_2
Wind offshore[54]	\$96 to \$177 per tonne of CO_2
Solar PV[54]	\$225 to \$101 per tonne of CO_2
Solar Thermal[54]	\$108 to \$181 per tonne of CO_2

The high CAC for solar and offshore wind can be explained by the low capacity factors of these technologies, mainly due to their intermittent nature. Thus it would take 3 to 4 times the capacity (in MW) to generate the same amount of MWh that a fossil fuel power plant would produce. [54]

3.4 CAC Calculations Using NGCC Power plants

Similar to the analysis presented in Section 3.3, CAC calculations were conducted using a NGCC power plant as the reference case. NGCC power plants are the second most common types of electricity generating power plants in the U.S. The CAC for NGCC power plants without CCS ranges between \$47 and \$136 per tonne of CO_2 avoided, and CAC using the reference case with CCS ranges between \$30 and \$151 per tonne of CO_2 avoided. Figure 24 illustrates the range of CACs for the four BECCS scenarios.

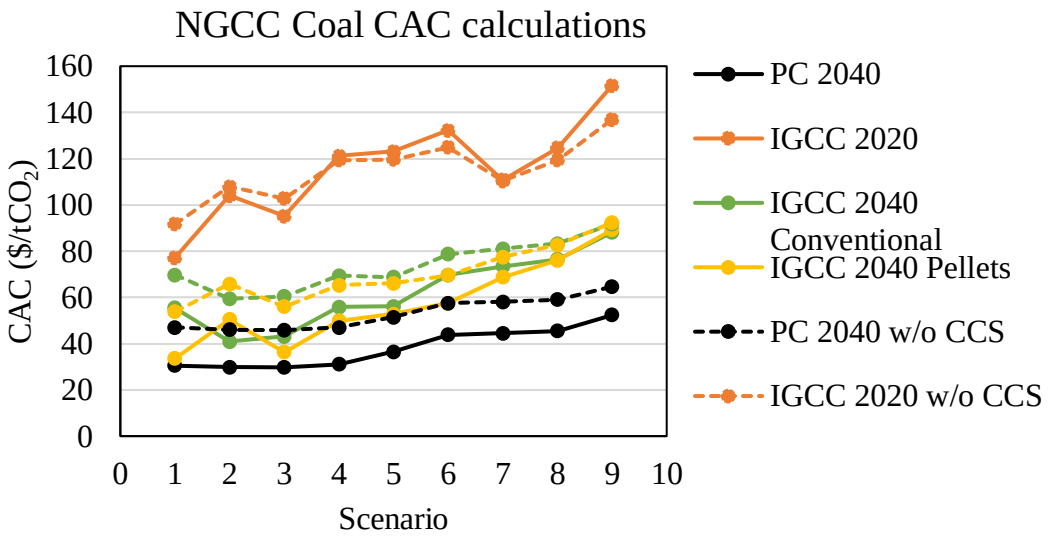

Figure 24: CO_2 avoidance cost (in $ per tonne of CO_2 avoided) using a PC power plant as a reference case. The dashed lines represent CAC costs using a reference case without CCS and the solid lines represent a reference case with CCS.

3.5 Sensitivity Analyses and Cost Breakdown of IGCC and PC Power plants

3.5.1 Sensitivity Analyses

Sensitivity analyses were conducted by changing one input parameter by ± 10% and measuring the change in an output variable, the revenue required to break even. The most significant parameters are presented in Table 11.

The tornado plot for the most significant parameters for IGCC and PC plants can be found in Figures 24 and 25. The black bars represent increasing the input parameter by 10% and the blue bars represent decreasing the input parameter by 10%.

In the case of PC power plants, the most influential parameters related to power plant performance include the boiler efficiency, CO_2 compression energy, and the costs associated with purchasing, using and regenerating the CCS solvent (MEA). In the case of

IGCC power plants, the turbine inlet temperature and feedstock cost are the most influential parameters. PC and IGCC power plant performance can be improved by optimizing the performance of the key units determined by the sensitivity analyses.

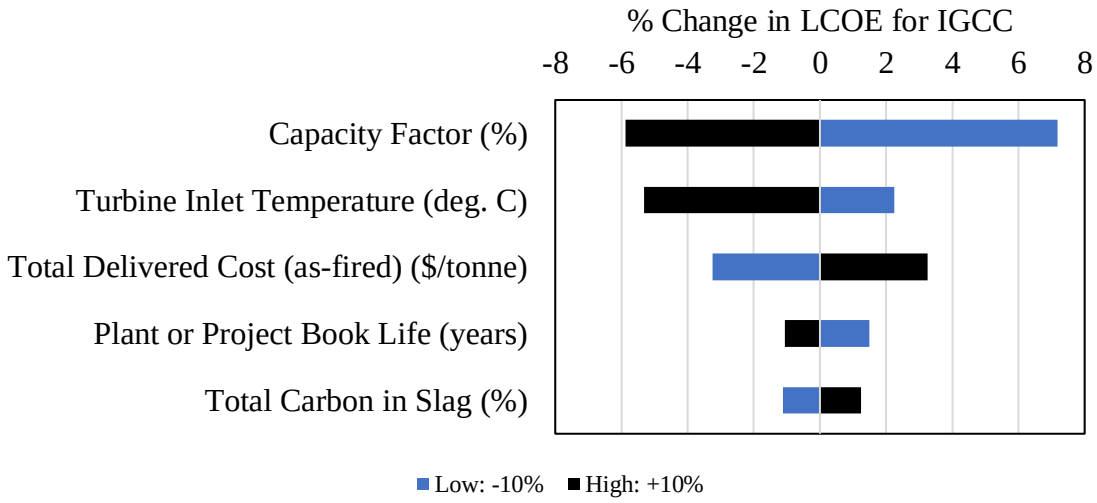

Figure 25: Tornado plot breakdown of significant parameters in an IGCC power plant running on pelletized biomass.[26]

Table 11. Most Significant Parameters in PC and IGCC Power plant Performance [26]

PC	IGCC
Boiler Efficiency	Capacity Factor
Capacity Factor	Turbine Inlet Temperature
CO_2 Unit compression Energy	Feedstock Cost
Discount Rate	Plant or Project Book Life
Feedstock Cost	Total Carbon in Slag
Gas Phase Pressure Drop	
MEA Cost	
Plant or Project Book Life	
Regenerator Heat Requirement	
Sorbent Concentration	
Sorbent Losses	

Note: Terms in boldface refer to units in the power plant that carry out CCS.

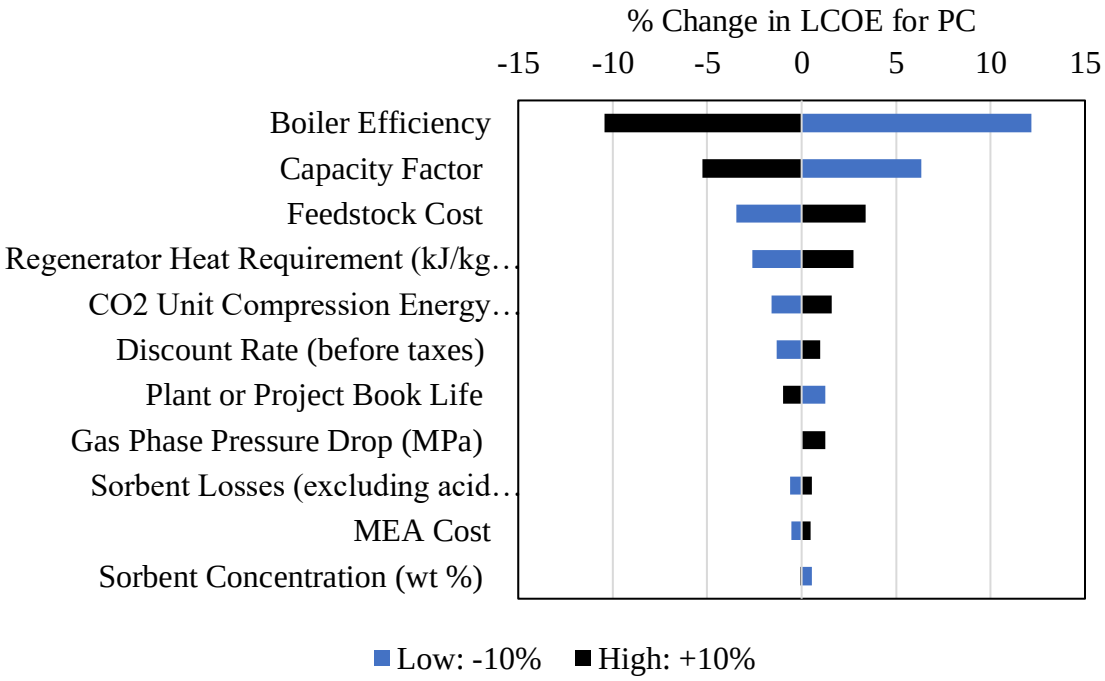

Figure 26: Tornado plot breakdown of significant parameters in a PC power plant running on pelletized biomass. [26]

3.5.2 Power plant Cost Breakdowns

The IECM was used to determine the most expensive units in BECCS power plants, and this result can be found in Figure 27. The IECM was used to predict operation and maintenance (O&M) costs, capital costs, and revenues required to break even. Average efficiency (in %HHV), capital cost, fixed and variable O&M costs, and capacity factors for the PC and IGCC scenarios are shown in Tables 12–15. An example cost breakdown for PC and IGCC power plants under the 50% CO_2 capture scenario is shown in Figure 27. Power consumed by emissions control technologies leads to lower net power produced and lost revenue. The IECM charges each unit in the plant for their internal use of electricity and treats this charge as a credit for the base plant. When comparing individual components

of the plant, these utility charges are taken into consideration. For total plant costs, the internal electricity offset for each individual unit adds up to zero and has no effect on O&M costs. The discount rate and plant lifetime were assumed to be 7% and 30 years, respectively. Modeling assumptions of PC and IGCC power plants on the IECM are found in Appendices B and C.

Table 12. Average Efficiency (%HHV), Capital Cost ($/kWe), Fixed O&M Cost ($/kWe/year), Variable O&M Cost ($/MWh), and Capacity Factor for the IGCC 2020 Conventional Logistics Scenario[26]

Scenario	CO_2 Captured (10^6 Tonnes)	Avg. Efficiency (% HHV)	Capital Cost ($/kW$_e$/Yr)	Fixed O&M Cost ($/kW$_e$/ Yr)	Variable O&M Cost ($/MWh)	Capacity Factor
10%	20	28	3117	146	78	0.80
20%	40	25	3397	156	97	0.78
30%	60	27	3225	150	87	0.79
40%	81	25	3454	158	107	0.78
50%	101	25	3410	153	106	0.78
60%	121	25	3383	149	110	0.78
70%	141	28	3136	136	101	0.79
80%	161	29	3130	137	103	0.79
90%	181	28	3261	143	120	0.79

Table 13. Average Efficiency (%HHV), Capital Cost ($/kWe), Fixed O&M Cost ($/kWe/year), Variable O&M Cost ($/MWh), and Capacity Factor for the IGCC 2040 Conventional Logistics Scenario[26]

Scenario	CO_2 Captured (10^6 Tonnes)	Avg. Efficiency (% HHV)	Capital Cost ($/kW$_e$/Yr)	Fixed O&M Cost ($/kW$_e$/ Yr)	Variable O&M Cost ($/MWh)	Capacity Factor
10%	82	26	3298	154	65	0.78
20%	164	25	3389	154	80	0.78
30%	246	26	3199	144	67	0.79
40%	328	25	3263	145	79	0.78
50%	410	25	3306	140	83	0.78
60%	491	25	3258	135	86	0.78
70%	573	25	3328	135	97	0.78
80%	655	25	3344	133	104	0.78
90%	737	25	3334	131	116	0.78

Table 14. Average Efficiency (%HHV), Capital Cost ($/kWe), Fixed O&M Cost ($/kWe/year), Variable O&M Cost ($/MWh), and Capacity Factor for the IGCC 2040 Conventional Logistics Scenario[26]

Scenario	CO_2 Captured (10^6 Tonnes)	Avg. Efficiency (% HHV)	Capital Cost ($/kW$_e$/Yr)	Fixed O&M Cost ($/kW$_e$/ Yr)	Variable O&M Cost ($/MWh)	Capacity Factor
10%	82	23	3566	164	86	0.77
20%	164	25	3346	156	72	0.78
30%	246	25	3312	149	73	0.78
40%	328	24	3390	150	85	0.78
50%	410	24	3340	142	86	0.78
60%	491	24	3454	146	99	0.77
70%	573	24	3400	139	102	0.77
80%	655	24	3352	135	104	0.78
90%	737	25	3334	131	116	0.78

Table 15. Average Efficiency (%HHV), Capital Cost ($/kWe), Fixed O&M Cost ($/kWe/year), Variable O&M Cost ($/MWh), and Capacity Factor for the 2040 Advanced (Pelletized) Logistics Scenario[26]

Scenario	CO_2 Captured (10^6 Tonnes)	Avg. Efficiency (% HHV)	Capital Cost ($/$kW_e$/Yr)	Fixed O&M Cost ($/$kW_e$/ Yr)	Variable O&M Cost ($/MWh)	Capacity Factor
10%	82	23	3807	95	78	0.66
20%	164	23	3798	96	78	0.66
30%	246	23	3799	95	79	0.66
40%	326	23	3809	95	81	0.66
50%	410	23	3810	95	89	0.66
60%	491	23	3848	96	99	0.66
70%	573	23	3844	96	100	0.66
80%	655	23	3828	97	101	0.66
90%	736	23	3858	98	110	0.66

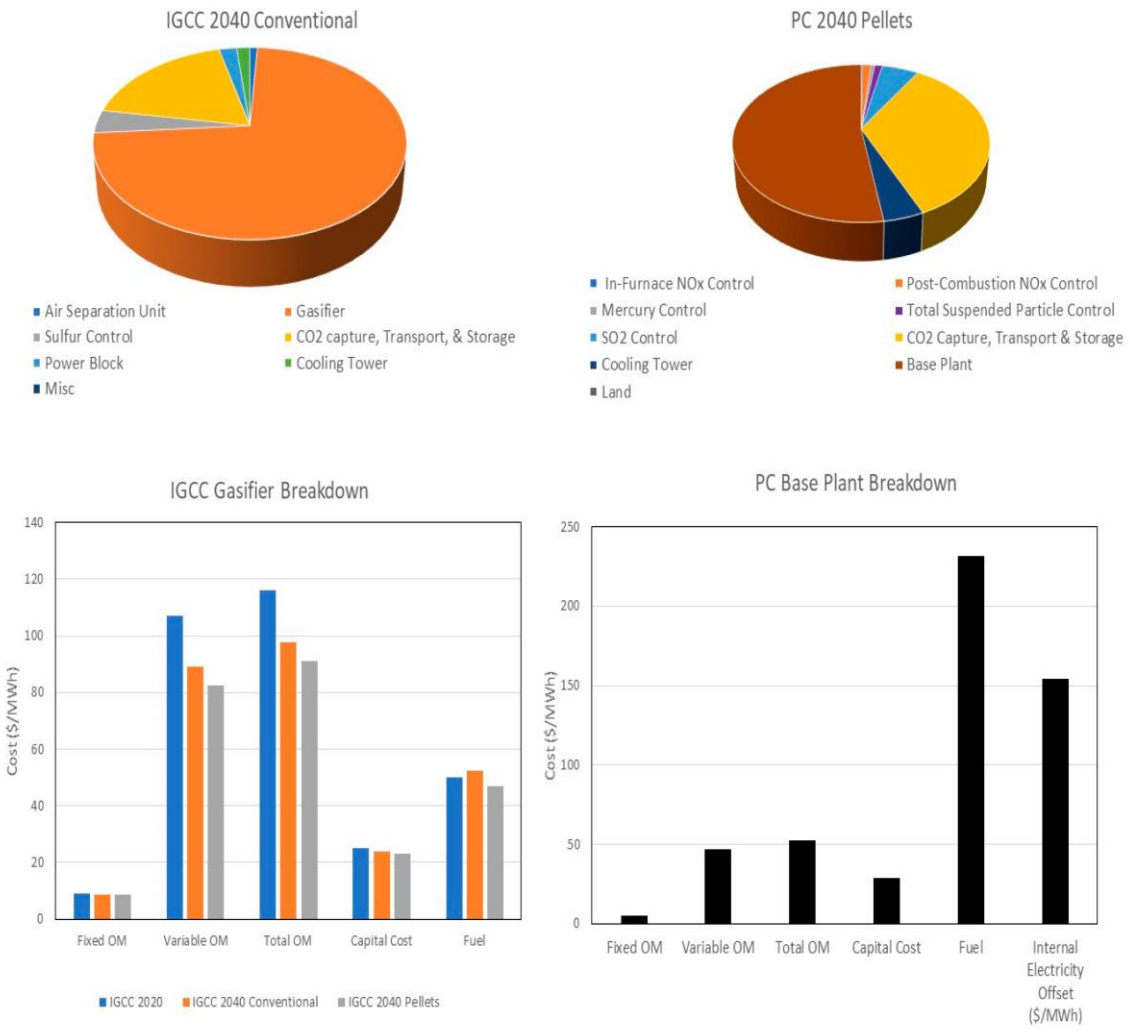

Figure 27: Starting clockwise from top left corner: Cost breakdown of IGCC power plants using non-pelletized fuel; cost breakdown of PC power plants using pelletized fuel; cost breakdown of most significant PC plant section (the base plant); cost breakdown of the most significant IGCC plant section (the gasifier). [26]

3.6 Potential Sites

Figure 28 illustrates all the potential BECCS power plant sites in the U.S. OR-Sage predicts a total of 4061 potential sites for BECCS power plants. The algorithm was used to develop a smaller selection of power plants by eliminating sites withing a certain radius from a previously established power plant. The larger the radius, the smaller the subset of power plants. For this study, a radius of 80 km was used. A map illustrating these power plants is presented in Figure 29.

Figure 28: Map illustrating all 4061 potential BECCS power plants.[26]

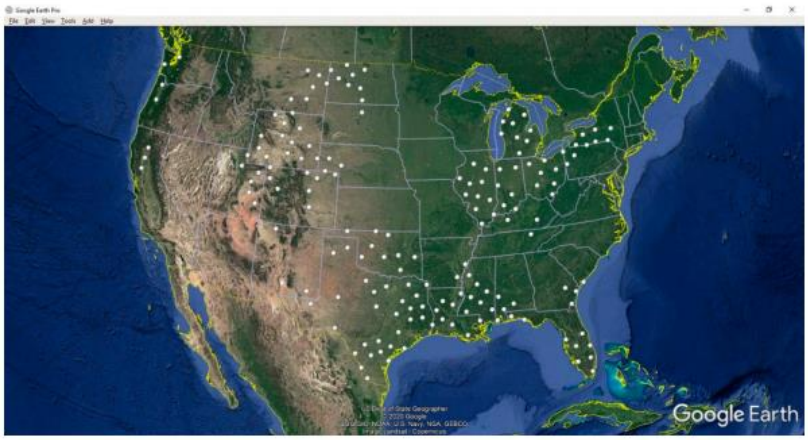

Figure 29: BECCS power plants that are at least 80km away from each other.[26]

4. FUTURE WORK AND CONCLUSIONS

4.1 Future Work

Sensitivity analyses performed on PC and IGCC power plants have identified several important parameters that can be optimized to decrease the cost of BECCS. For PC power plants, the main areas of potential optimization include the boiler performance, heat losses to steam, and the CCS unit performance. The boiler performance and heat losses to steam are two parameters that greatly influence the thermal efficiency of a PC power plant. Since the regeneration of the sorbent used for CCS is highly energy intensive, optimizing the absorption and regeneration can improve the performance of PC power plants. The CCS unit can be optimized by managing the sorbent losses due to degradation, effective heat recovery, and the CO_2 compression requirements.

According to Gadalla et al., IGCC performance can be optimized through the following process improvements: integration of the air separation unit (ASU) with the gas turbine, increasing turbine performance, and effective heat recovery.[55, 56] The integration of the ASU with the gas turbine can be accomplished by extracting the air from the turbine (as the input for the ASU) and using nitrogen injection from the ASU into the gas turbine. Extracting air from the gas turbine helps decrease the energy demand of the ASU, and the nitrogen injection helps reduce NOx emissions. Turbine performance can be increased by increasing the pressure ratio and the inlet temperature. Sensitivity analyses of IGCC performance indicated that increasing the inlet temperature of the gas turbine and decreasing the feedstock moisture content can improve IGCC performance.

Feedstock transportation could potentially be optimized by exploring other transportation methods. For example, transport of fuel within the U.S. can be modeled using trains instead of trucks. The pelletization and pretreatment processes can also be improved by determining optimal torrefaction temperatures and residence times for each feedstock.[57]

Another approach to reducing the cost of BECCS is by converting coal power plants into biomass power plants. This approach could significantly save capital costs, and even though the performance of the plant may not be optimal, the benefit may be greater than the loss in power generation due to the lower plant performance. It should be noted, however, that the US coal fleet is quite old.

Another area for improvement includes finding alternative fuels for BECCS. Apart from biomass, research has shown that plastics could be used to co-fire with traditional biomass in IGCC power plants. Plastics in municipal waste have extremely high energy content, and according to the EIA, since 1989 the ratio of non-biogenic waste (i.e., plastics) in municipal waste has been steadily increasing.[58, 59] This provides an opportunity to use a rather cheap, readily available source of fuel. Polyethylene terephthalate (PET) and high density polyethylene (HDPE) for example have heat contents of 21 MJ per kg and 40 MJ per kg, respectively, both of which are comparable to the heat content of coal (which typically ranges between 17.0 and 23.9 MJ per kg).[60, 61] Furthermore, these recyclable plastic fuels are often found near places with high population density, thus reducing potential supply chain transportation costs. One disadvantage, however, is the potential to produce toxins like dioxin, furans, and mercury during the gasification process. Due to the nature and concentrations of these pollutants, specialized capture technologies will be required.

One last scope for improvement includes fixing CO_2 as biochar using BECCS. Biochar is the end-product of the thermochemical conversion of biomass in the absence of oxygen, i.e., through pyrolysis. Biochar has great potential in sequestering carbon in the long term and can also be used as a soil ameliorant in the short term to increase soil health.[62] Furthermore, biochar has been proven to be a very stable form of fixed CO_2 and will not release any CO_2 into the atmosphere for centuries.[63, 64] The main issue with biochar is that it is relatively expensive since pyrolysis is an energy intensive process. Biochar handling must also be explored. Particulate matter from stored biochar can potentially be harmful for humans and can also be a fire hazard.

4.2 Conclusions

BECCS has the capability of reducing atmospheric CO_2. This thesis explores potential supply of fuel and cost of BECCS under a range of feedstock options, power plant configurations and locations, and logistics. Results of the simulations performed for this thesis indicated that, at a 90% capacity, BECCS has the potential to remove around 181 million tonnes of CO_2 in 2020 and 737 million tonnes in 2040 from the atmosphere in the U.S. Scenario specific average costs indicated that the cost of capturing, transporting, and storing CO_2 ranges between $42 and $137 per tonne of CO_2 depending on the type of power generation technology, cost accounting equation, and level of biomass utilization. In 2018, roughly 8 billion metric tonnes of CO_2 were released into the atmosphere in the U.S., with 1.1 billion tonnes of CO_2 coming from coal power plants.[4] Converting these coal power plants to BECCS power plants in the near term could help reduce total CO_2 emission to 6.7 billion tonnes. Similarly, in the longer term, by replacing coal power plants with BECCS

power plants, the U.S. can limit its annual CO_2 emissions to around 6.1 billion tonnes. According to climate goals outlined by the Paris Agreement, BECCS has the potential to sequester roughly 25% of carbon needed to achieve carbon neutrality.

CAC calculations suggest that the cost of CCS using BECCS ranges from $45 to $85 per tonne of CO_2 avoided when comparing to reference case power plants without CCS, depending on level of biomass utilization, power plant type, and pelletization. The CAC calculations used to compare BECCS to PC and IGCC power plants with CCS help calculate the additional cost of CO_2 removal from the atmosphere. Depending on the type of power plant used, level of biomass utilization and type of feed, this CAC ranges between $30 and $140 per tonne of CO_2. The CAC of BECCS is competitive with some neutral emissions technologies; it is lower than that of solar and offshore wind, but higher than onshore wind and nuclear.

APPENDIX A: FLOW OF INFORMATION IN THIS THESIS

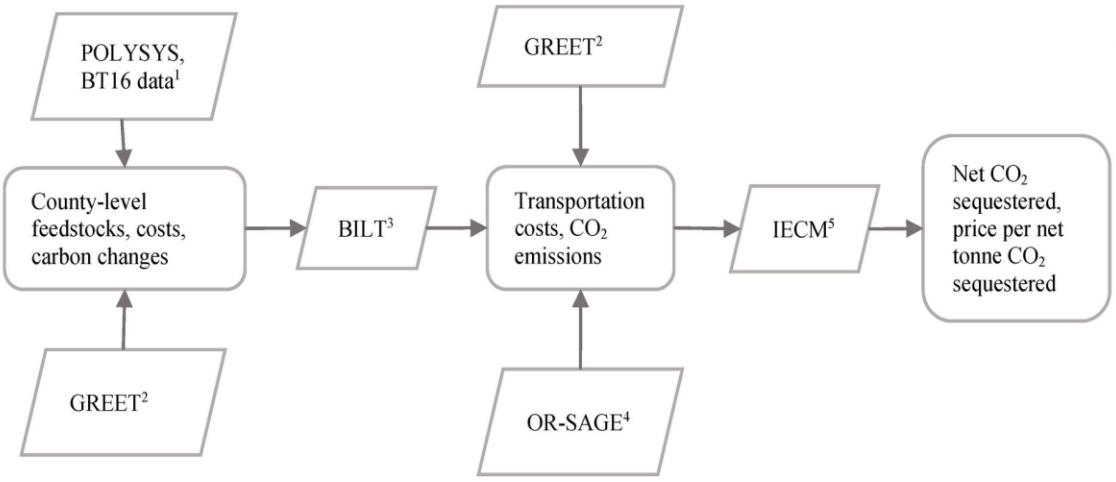

Figure 30: Flow of information in this work. This thesis is mostly focused on IECM calculations. [26]

Table 16. Four BECCS Scenarios in this Thesis[26]

Case	Power plant Technology	Year	Fuel Type
1	IGCC	2020	Non-pelletized (conventional)
2	PC	2040	Pelletized (advanced)
3	IGCC	2040	Non-pelletized (conventional)
4	IGCC	2040	Pelletized (advanced)

APPENDIX B: PARAMETERS USED IN PC SIMULATIONS

Variables	Value
Capacity factor	90%
Ambient air temperature	18.89
ambient air pressure	0.10
relative humidity	50%
water life cycle assessment enabled?	yes
SO2 emission constraint	0.03
NO2 emission constraint	0.22
Particulate emission constraint	0.01
Total mercury removal efficiency	70.00
Total CO2 removal efficiency	90.00
tax on SO2	0.00
tax on NO2	0.00
tax on CO2	0.00
Year costs reported	2017.00
constant or current dollars	constant
discount rate (before taxes)	0.07
fixed charge factor	0.11
plant or project book life	30.00
real bond interest rate	5.83%
real preferred stock return	5.34%
real common stock return	8.74%
percent debt	45.00%
percent equity (preferred stock)	10.00%
percent equity (real stock)	45.00%
federal tax rate	34.00%
state tax rate	4.15%
property tax rate	2.00%
investment tax credit	0.00%
as-delivered coal cost	0.00
natural gas cost	260.20
real escalation rate	0.00
internal cost of electricity for component allocations	base plant
internal electricity price	37.65
land cost use	3000.00
total land requirement	0.52
construction time	3.00

financing cost (%TCP)	0.00
other owners costs (%TCP)	0.00
activated carbon	2417.00
alum	407.70
ammonia	149.90
caustic	499.20
dibasic acid	639.30
flocculant polymer	4786.00
lime	110.30
limestone	25.39
MEA	2589.00
SCR catalyst	6003.00
Urea	559.40
Water	0.30
Hydrated lime	168.10
Taxes & insurance	0.00
Operating labor rate	34.65
Real escalation rate	0.00
Gross Electrical Output	
Unit type	Supercritical
steam cycle heat rate (HHV)	1.09E+04
boiler firing type	tangential
boiler efficiency	94%
excess air for furnace	20
leakage air at preheater	10
gas temperature exiting economizer	371.1
gas temperature exiting air preheater	148.9
percent water in bottom ash sluice	0
hydrated lime for so3 removal	1059
coal pulverizer	1.387
steam cycle pumps	0.16
forced/induced draft fans	3.891
miscellaneous	1.04
steam energy added in Boiler	2680
Boiler Blowdown	6%
Miscellaneous Steam Losses	0%
Demineralizer Underflow	9%
Cooling Water Temperature Rise	11.11
Auxiliary heat exchanger load	1%
Percent ash entering flue gas stream	65%

sulfur retained in fly ash	25%
percent of SOx as SO3	0.00056
Preheater SO3 removal efficiency	10%
Nitrogen Oxide emission rate	0.3049
percent of NOx as NO	95%
Concentration of Carbon in collected ash	0%
percent of burned carbon as CO	0%
Construction time	3.00
%PFC Allocated to Equipment	64%
%PFC Allocated to Materials	2%
General Facilities Capital	10%
Engineering & Home Office Fees (E)	7%
Process Contingency Cost (C)	2%
Project Contingency Cost	10%
Royalty Fees	0%
Fixed Operating Cost	1
Variable Operating Cost	1
Miscellaneous Capital Cost	2%
Inventory Capital	0%
Financing Cost	0%
Other Owner's Costs	0%
% TCR Amortized	0%
As-Delivered Coal Cost	0
Waste Disposal Cost	11.7
Water Cost	0.2983
Hydrated Lime Cost	168.1
Electricity Price (Internal)	37.65
Number of Operating Jobs	20
Number of Operating Shifts	4.75
Operating Labor Rate	34.65
Total Maintenance Cost	1.975
Maintenance Cost Allocated to Labor	35
Administrative & Support Cost	7
Taxes & Insurance	0
Actual NOx Removal Efficiency (%)	44.39%
Maximum NOx Removal Efficiency (%)	50%
Combustion Modifications	8.913
Combustion Modifications	8.913
% TCR Amortized (%)	0%
Electricity Price (Internal)	37.65

Combustion Modifications	1.50%
Actual NOx Removal Efficiency	50%
Maximum NOx Removal Efficiency	90%
Particulate Removal Efficiency	0%
Number of SCR Trains	2
Number of Spare SCR Trains	0
Number of Dummy Catalyst Layers	1
Number of Initial Catalyst Layers	3
Number of Reserve Catalyst Layers	0
Catalyst Replacement Interval	1.00E+04
Catalyst Space Velocity (1/hr)	4651
Ammonia Stoichiometry	0.5089
Steam to Ammonia Ratio (mol H2O/mol NH3)	19
Steam for Soot Ratio	6.78E-02
Total Pressure Drop Across SCR (cm H2O gauge)	22.86
Oxidation of SO2 to SO3	0.63%
Hot-Side SCR Power Requirement (% MWg)	0.86%
Space Velocity (1/hr)	2500
Catalyst Replacement Interval (hours)	5694
Ammonia Slip (ppmv)	2
Temperature	644.4
NOx Removal Efficiency (%)	80%
NOx Concentration (ppmw)	500
Minimum Activity (fraction)	0.5
Reference Time (hours)	1.00E+04
Activity at Reference Time (fraction)	0.85
Ammonia Deposition on Preheater (%)	5%
Ammonia Deposition on Fly Ash (%)	50%
Ammonia in High Concentration Wash Water (mg/liter)	310
Ammonia in Low Concentration Wash Water (mg/liter)	40
Ammonia Removed from Wash Water (%)	67%
Construction Time (years)	3
%PFC Allocated to Equipment (%PFC)	79.73%
%PFC Allocated to Materials (%PFC)	0%
General Facilities Capital (%PFC)	10%
Engineering & Home Office Fees (E) (%PFC)	10%
Process Contingency Cost (C) (%PFC)	7.12%
Project Contingency Cost (%(PFC+E+C))	15%
Royalty Fees (%PFC)	0%
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1

Miscellaneous Capital Cost (%TPI)	2%	
Inventory Capital (%TPC)	0.50%	
Financing Cost (%TPC)	0%	
Other Owner's Costs (%TPC)	0%	
% TCR Amortized (%)	0%	
Catalyst Cost ($/cu m)	6003	
Ammonia Cost ($/tonne)	149.9	
Electricity Price (Internal) ($/MWh)	37.65	
Number of Operating Jobs (jobs/shift)	0.46	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65%	
Total Maintenance Cost (%TPC)	2%	
Maintenance Cost Allocated to Labor (% total)	40%	
Administrative & Support Cost (% total labor)	30%	
Taxes & Insurance (%TPC)	0%	
Particulate Removal Efficiency (%)	99.46	
Actual SO3 Removal Efficiency (%)	25	
Collector Plate Spacing (centimeters)	30.48	
Specific Collection Area (sq m/Macmm)	861.9	
Plate Area per T-R Set (sq m/T-R set)	2206	
Percent Water in ESP Discharge (%)	0	
Cold-Side ESP Power Requirement (% MWg)	0.2149	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	60.16	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	1	
Engineering & Home Office Fees (E) (%PFC)	5	
Process Contingency Cost (C) (%PFC)	0	
Project Contingency Cost (%(PFC+E+C))	15	
Royalty Fees (%PFC)	0	
Months of Fixed O&M (months)	1	
Months of Variable O&M (months)	1	
Miscellaneous Capital Cost (%TPI)	2	
Inventory Capital (%TPC)	0.5	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Water Cost ($/kliter)	0.2983	
Waste Disposal Cost ($/tonne)	18.79	
Electricity Price (Internal) ($/MWh)	37.65	

Number of Operating Jobs (jobs/shift)	0.97	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	1.54	
Maintenance Cost Allocated to Labor (% total)	47.63	
Administrative & Support Cost (% total labor)	30	
Taxes & Insurance (%TPC)	0	
System Used	MEA	
Auxiliary Gas Boiler?	None	
CO2 Product Compressor Used?	Yes	
Compressor Type	6-stage	
Flue Gas Bypass Control	No Bypass	
Direct Contact Cooler (DCC) Used?	Yes	
SO2 Polisher Used?	Yes	
SO2 Polisher Outlet Concentration (ppmv)	10	
Temperature Exiting DCC (deg. C)	45	
Maximum CO2 Removal Efficiency (%)	90	
Absorber CO2 Removal Efficiency (%)	90	
SO2 Removal Efficiency (%)	99.5	
SO3 Removal Efficiency (%)	99.5	
NO2 Removal Efficiency (%)	0	
HCl Removal Efficiency (%)	95	
Particulate Removal Efficiency (%)	50	
Maximum Train CO2 Capacity (tonne/hr)	208.7	
Number of Operating Absorbers (integer)	3	
Number of Spare Absorbers	0	
Maximum CO2 Compressor Capacity (tonne/hr)	299.4	
Number of Operating CO2 Compressors (integer)	3	
Number of Spare CO2 Compressors	0	
Amine Scrubber Power Requirement (% MWg)	19.16	
Sorbent Concentration (wt %)	30	
Lean CO2 Loading (mol CO2/mol sorb)	0.2	
Sorbent Losses (excluding acid gasses) (kg/tonne CO2)	2.25	
Sorbent Recovered (kg/tonne CO2)	0.1985	
Liquid-to-Gas Ratio (ratio)	3.741	
Ammonia Generation (mol NH3/mol sorb)	1	
Gas Phase Pressure Drop (MPa)	1.38E-02	
ID Fan Efficiency (%)	75	
Makeup Water for Wash Section (% raw flue gas)	0.8	
Activated Carbon Used (kg/tonne CO2)	7.50E-02	

Regenerator Heat Requirement (kJ/kg CO2)	4722	
Regenerator Steam Heat Content (kJ/kg steam)	3194	
Heat-to-Electricity Efficiency (%)	18.7	
Solvent Pumping Head (MPa)	0.2068	
Pump Efficiency (%)	75	
Percent Solids in Reclaimer Waste (%)	40	
Capture System Cooling Duty (t H2O/t CO2)	104.3	
CO2 Product Pressure (MPa)	13.79	
CO2 Product Purity (vol %)	99.5	
CO2 Compressor Efficiency (%)	80	
CO2 Unit Compression Energy (kWh/tonne CO2)	117.9	
CO2 Transport Method	Pipeline	
CO2 Storage Method	Geologic	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	76.64	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	10	
Engineering & Home Office Fees (E) (%PFC)	7	
Process Contingency Cost (C) (%PFC)	10	
Project Contingency Cost (%(PFC+E+C))	20	
Royalty Fees (%PFC)	0.5	
Months of Fixed O&M (Preproduction) (months)	1	
Months of Variable O&M (Preproduction) (months)	1	
Miscellaneous Capital Cost (Preproduction) (%TPI)	2	
Inventory Capital (%TPC)	0.5	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Sorbent Cost ($/tonne)	2589	
Inhibitor Cost (% of MEA)	20	
Activated Carbon Cost ($/tonne)	2417	
Caustic (NaOH) Cost ($/tonne)	499.2	
Water Cost ($/kliter)	0.2983	
Reclaimer Waste Disposal Cost ($/tonne)	255.8	
Electricity Price (Internal) ($/MWh)	37.65	
CO2 Transport Cost (Levelized) ($/tonne)	1.439	
CO2 Storage Cost ($/tonne)	2.406	
Number of Operating Jobs (jobs/shift)	2	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	2.5	

Maintenance Cost Allocated to Labor (% total)	40	
Administrative & Support Cost (% total labor)	30	
Taxes & Insurance (%TPC)	0	
Pipeline Region	Midwest US	
Total Pipeline Length (km)	100	
Net Pipeline Elevation Change (Plant->Inj.) (meters)	0	
Number of Booster Stations (integer)	0	
Compressor/Pump Driver	Electric	
Booster Pump Efficiency (%)	75	
Design Pipeline Flow (% plant cap)	100	
Design Pipeline Flow (tonne/yr)	5.44E+06	
Actual Pipeline Flow (tonne/yr)	4.90E+06	
Inlet Pressure (@ power plant) (MPa)	13.79	
Min Outlet Pressure (@ storage site) (MPa)	10.3	
Average Ground Temperature (deg. C)	5.6	
Pipe Material Roughness (centimeters)	4.57E-03	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	76.64	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	0	
Engineering & Home Office Fees (E) (%PFC)	0	
Process Contingency Cost (C) (%PFC)	0	
Project Contingency Cost (%(PFC+E+C))	0	
Royalty Fees (%PFC)	0	
Months of Fixed O&M (months)	0	
Months of Variable O&M (months)	0	
Miscellaneous Capital Cost (%TPI)	0	
Inventory Capital (%TPC)	0	
% TCR Amortized (%)	0	
Booster Pump Operating Cost (%PFC)	1.5	
Fixed O&M Cost ($/km-yr)	3100	
Reservoir Depth (meters)	1219	
Reservoir Thickness (meters)	304.8	
Reservoir Horizontal Permeability (mD)	100	
Reservoir Porosity (%)	12	
Storage Coefficient (%)	5.8	
Reservoir Surface Temperature (deg. C)	45.44	
Geographical Area for CO2 Storage (sq km)	7.02E+04	
Performance Model	Law & Bachu	
Project Average Injection Rate (Mt CO2/yr)	4.896	

Design Maximum Injection Rate per Well (Mt CO2/yr)	6.12	
Monitoring Well Density		
Wells in Reservoir (sq km/well)	10.36	
Wells Above Seal (sq km/well)	5.18	
Wells that are Dual Completed (sq km/well)	10.36	
Wells Groundwater (Wells/Inj. Well)	3	
Wells Vadose Zone (Wells/Inj. Well)	3	
Dual Completed Wells in Reservoir (%)	100	
AOR Margin 3D (% of Plume)	30	
Regional Evaluation Duration (years)	1	
Site Characterization Duration (years)	1	
Permitting Duration (years)	1	
General Facilities Factor (%)	10	
Administrative Factor (E) (%)	10	
Process Contingency Factor (C) (%PFC)	20	
Project Contingency Factor (%(PFC+E+C))	20	
Miscellaneous Capital Cost (%TPI)	0	
% TCR Amortized (%)	0	
Operation Duration (years)	30	
Contingency Factor (%)	20	
Geophysical Survey: 3D Seismic ($/sq km)	6.18E+04	
Labor Rates		
Geologist ($/hr)	107.2	
Engineer ($/hr)	110.6	
Landman ($/hr)	75	
Miscellaneous Operations (%)	1	
PISC and Site Closure Duration (years)	50	
Well Seismic: VSP Tool Costs ($/well)	3.00E+05	
Miscellaneous PISC and Site Closure (%)	0.5	
Furnace Removal (total) (%)	7	
Cold-Side ESP (total w/o control) (%)	0	
Cold-Side ESP (oxidized) (%)	55.84	
Cold-Side ESP (elemental) (%)	55.84	
Wet FGD (oxidized) (%)	95	
Wet FGD (elemental) (%)	0	
Wet FGD (particulate) (%)	0	
Percent Increase in Speciation		
In-furnace NOx (oxidized) (%)	0	
SNCR (oxidized) (%)	0	
Hot-Side SCR (oxidized) (%)	35	

Carbon Injection Rate (*) (kg C/Macmm)	38.89	
Carbon Injection Power Reqmt (% MWg)	2.22E-02	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	63.82	
%PFC Allocated to Materials (%PFC)	2.46	
General Facilities Capital (%PFC)	5	
Engineering & Home Office Fees (E) (%PFC)	10	
Process Contingency Cost (C) (%PFC)	5	
Project Contingency Cost (%(PFC+E+C))	15	
Royalty Fees (%PFC)	0	
Fixed Operating Cost (months)	1	
Variable Operating Cost (months)	1	
Miscellaneous Capital Cost (%TPI)	2	
Inventory Capital (%TPC)	0.5	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Activated Carbon Cost (w. shipping) ($/tonne)	2417	
Disposal Cost ($/tonne)	18.79	
Electricity Price (Internal) ($/MWh)	37.31	
Number of Operating Jobs (jobs/shift)	0.175	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	1.48E-02	
Maintenance Cost Allocated to Labor (% total)	40	
Administrative & Support Cost (% total labor)	25	
Taxes & Insurance (%TPC)	0	
Reagent	Limestone	
Flue Gas Bypass Control	No Bypass	
Demister for Outlet Flue Gas	No Demister	
Maximum SO2 Removal Efficiency (%)	98	
Scrubber SO2 Removal Efficiency (%)	98	
Scrubber SO3 Removal Efficiency (%)	50	
Particulate Removal Efficiency (%)	50	
Absorber Capacity (% acmm)	100	
Number of Operating Absorbers (integer)	1	
Number of Spare Absorbers	0	
Liquid-to-Gas Ratio (lpm/kacmm)	4.41E+04	
Reagent Stoichiometry (mol Ca/mol S rem)	1.03	
Reagent Purity (wt %)	92.4	

Reagent Moisture Content (wt %)	0	
Total Pressure Drop Across FGD (cm H2O gauge)	25.4	
Temperature Rise Across ID Fan (deg. C)	7.778	
Gas Temperature Exiting Scrubber (deg. C)	62.33	
Gas Temperature Exiting Reheater (deg. C)	62.33	
Entrained Water Past Demister (% evap H2O)	0.79	
Wet FGD Power Requirement (% MWg)	6.973	
Oxidation of CaSO3 to CaSO4 (%)	90	
Excess Air for Oxidation (% stoic)	0	
Excess Water for Oxidation (% stoic)	0	
Chloride Removal Efficiency (%)	90	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	79.73	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	10	
Engineering & Home Office Fees (E) (%PFC)	10	
Process Contingency Cost (C) (%PFC)	2	
Project Contingency Cost (%(PFC+E+C))	15	
Royalty Fees (%PFC)	0.5	
Months of Fixed O&M (Preproduction) (months)	1	
Months of Variable O&M (Preproduction) (months)	1	
Miscellaneous Capital Cost (Preproduction) (%TPI)	2	
Inventory Capital (%TPC)	6.46E-02	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Bulk Reagent Storage Time (days)	60	
Limestone Cost ($/tonne)	25.39	
Lime Cost ($/tonne)	110.3	
Waste Disposal Cost ($/tonne)	14.47	
Electricity Price (Internal) ($/MWh)	37.31	
Number of Operating Jobs (jobs/shift)	6.67	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	4.467	
Maintenance Cost Allocated to Labor (% total)	40	
Administrative & Support Cost (% total labor)	30	
Taxes & Insurance (%TPC)	0	

APPENDIX C: PARAMETERS USED IN IGCC SIMULATIONS

Note: NGCC power plants were simulated with identical IGCC parameters for everything but the fuel and syngas sections.

Title	Value
Number of Gas Turbines	2
Gross Electrical Output (MWg)	630
Capacity Factor (%)	90
Process Water Demand Factor (l/MWh-net)	583
Ambient Air Temperature (Dry Bulb Average) (deg. C)	18.89
Ambient Air Pressure (MPa)	0.1014
Relative Humidity (Average) (%)	50
Ambient Air Humidity (kg H2O/kg dry air)	6.77E-03
Capital Cost Multipliers (ratio of Local/Default value)	
Construction Equipment Cost	1
Construction Materials Cost	1
Construction Labor Cost	1
Construction Labor Productivity	1
Seismicity Factor	1
Sulfur Dioxide (SO2) ($/tonne)	0
Nitrogen Oxide (Equivalent NO2) ($/tonne)	0
Carbon Dioxide (CO2) ($/tonne)	0
Year Costs Reported	2017
Constant or Current Dollars?	Constant
Discount Rate (Before Taxes) (fraction)	7.09E-02
Fixed Charge Factor (FCF) (fraction)	0.1128
Plant or Project Book Life (years)	30
Real Bond Interest Rate (%)	5.83
Real Preferred Stock Return (%)	5.34
Real Common Stock Return (%)	8.74
Percent Debt (%)	45
Percent Equity (Preferred Stock) (%)	10
Percent Equity (Common Stock) (%)	45
Federal Tax Rate (%)	34
State Tax Rate (%)	4.15
Property Tax Rate (%)	2
Investment Tax Credit (%)	0
As-Delivered Coal Cost ($/tonne)	0
Auxiliary Gas Cost ($/mscm)	260.2
Real Escalation Rate (fuel) (%/yr)	0

Internal Cost of Electricity for Component Allocations	Base Plant
Internal Electricity Price ($/MWh)	10.76
Land Use Cost ($/acre)	3000
Total Land Requirement (acres/MWg)	0.517
Construction Time (years)	4
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
Activated Carbon Cost ($/tonne)	2417
Ammonia Cost ($/tonne)	149.9
Beavon-Stretford Catalyst Cost ($/cu m)	7151
Caustic (NaOH) Cost ($/tonne)	499.2
Claus Plant Catalyst Cost ($/tonne)	577.8
Glycol Cost ($/kg)	6.391
Shift Reactor Catalyst (Hi-T) ($/cu m)	2612
Shift Reactor Catalyst (Low-T) ($/cu m)	1.31E+04
Urea Cost ($/tonne)	559.4
Ionic Liquid Cost ($/tonne)	1.10E+04
Water Cost ($/kliter)	0.2983
Taxes & Insurance (%TPC)	0
Operating Labor Rate ($/hr)	34.65
Sulfur Byproduct Credit ($/tonne)	70.11
Real Escalation Rate (for all above) (%/yr)	0
Oxidant Composition	
Oxygen (O2) (vol %)	95
Argon (Ar) (vol %)	4.234
Nitrogen (N2) (vol %)	0.7657
Final Oxidant Pressure (MPa)	3.999
Maximum Train Capacity (tonne/hr)	550
Number of Operating Trains (integer)	1
Number of Spare Trains	0
Unit Separation ASU Energy (kWh/tonne)	6860
Total Cryogenic ASU Energy (% MWg)	1.53E-02
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	76.64
%PFC Allocated to Materials (%PFC)	0
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	5
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2

Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	2
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
Capital Cost Process Area	
Air Separation Unit (retro $/new $)	1
Final Oxidant Compression (retro $/new $)	1
Gasifier Area	
Gasifier Temperature (deg. C)	1343
Gasifier Pressure (MPa)	4.24
Total Water or Steam Input (mol H2O/mol C)	1.274
Oxygen Input from ASU (mol O2/mol C)	0
Total Carbon in Slag (%)	3
Sulfur Loss to Solids (%)	0
Coal Ash in Raw Syngas (%)	0
Percent Water in Slag Sluice (%)	0
Number of Operating Trains (integer)	1
Number of Spare Trains	1
Particulate Removal Efficiency (%)	100
Power Requirement (% MWg)	2.40E-06
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	63.82
%PFC Allocated to Materials (%PFC)	2.46
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	13.82
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	1
Financing Cost (%TPC)	0

Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Slag Disposal Cost ($/tonne)	17.73
Water Cost ($/kliter)	0.2983
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	4.225
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
COS to H2S Conversion Efficiency (%)	98.5
Sulfur Removal Unit	
H2S Removal Efficiency (%)	98
COS Removal Efficiency (%)	33
CO2 Removal Efficiency (%)	0
Max Syngas Capacity per Train (tonne/hr)	225.2
Number of Operating Absorbers (integer)	2
Power Requirement (% MWg)	5.52E-02
Sulfur Recovery Efficiency (%)	95
Max Sulfur Capacity per Train (tonne/hr)	4.536
Number of Operating Absorbers (integer)	1
Power Requirement (% MWg)	6.89E-02
Tailgas Treatment	
Sulfur Recovery Efficiency (%)	99
Power Requirement (% MWg)	0.2097
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	79.73
%PFC Allocated to Materials (%PFC)	0
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	10
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0

% TCR Amortized (%)	0
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	79.73
%PFC Allocated to Materials (%PFC)	0
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	10
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Selexol Solvent Cost ($/kg)	6.391
Claus Plant Catalyst Cost ($/tonne)	577.8
Beavon-Stretford Catalyst Cost ($/cu m)	7151
Sulfur Byproduct Credit ($/tonne)	70.11
Sulfur Disposal Cost ($/tonne)	12.08
Sulfur Sold on Market (%)	90
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Total Maintenance Cost (%TPC)	1.961
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
COS Conversion System - Hydrolyzer (retro $/new $)	1
Sulfur Removal System - Selexol (retro $/new $)	1
Sulfur Recovery System - Claus (retro $/new $)	1
Tail Gas Treatment - Beavon-Stretford (retro $/new $)	1
Water-Gas Shift Reactor	
CO to CO2 Conversion Efficiency (%)	95
COS to H2S Conversion Efficiency (%)	98.5
Steam Added (mol H2O/mol CO)	0.99
Maximum Train CO2 Capacity (tonne/hr)	139.6
Number of Operating Absorbers (integer)	1
Number of Spare Absorbers	0
Thermal Energy Credit (% MWg)	3.87
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	76.64
%PFC Allocated to Materials (%PFC)	0

(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	5
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
High Temperature Catalyst Cost ($/cu m)	2612
Low Temperature Catalyst Cost ($/cu m)	1.31E+04
Water Cost ($/kliter)	0.2983
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	1
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	1.969
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
High Temperature Reactor (retro $/new $)	1
Low Temperature Reactor (retro $/new $)	1
Heat Exchangers (retro $/new $)	1
CO2 Removal Efficiency (%)	90
H2S Removal Efficiency (%)	94
Max Syngas Capacity per Train (tonne/hr)	287.3
Number of Operating Absorbers (integer)	1
Number of Spare Absorbers	0
CO2 Product Compressor Used?	Yes
Power Requirement (% MWg)	0
CO2 Product Stream	
CO2 Product Pressure (MPa)	13.79
CO2 Compressor Efficiency (%)	80
CO2 Unit Compression Energy (kWh/tonne CO2)	0
CO2 Transport Method	Pipeline
CO2 Storage Method	Geologic
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	76.64

%PFC Allocated to Materials (%PFC)	0
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	10
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Bulk Reagent Storage Time (days)	60
Glycol Cost ($/kg)	6.391
Waste Disposal Cost ($/tonne)	0
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	2
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	4.902
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Gas Turbine/Generator	
Gas Turbine Model	GE 7FB
Number of Gas Turbines	2
Total Gas Turbine Output (MW)	0
Fuel Gas Moisture Content (vol %)	33
Turbine Inlet Temperature (deg. C)	1371
Turbine Back Pressure (MPa)	1.38E-02
Adiabatic Turbine Efficiency (%)	85.7
Shaft/Generator Efficiency (%)	98
Air Compressor	
Pressure Ratio (outlet/inlet) (ratio)	18.5
Adiabatic Compressor Efficiency (%)	87.5
Combustor	
Combustor Inlet Pressure (MPa)	1.875
Combustor Pressure Drop (MPa)	2.76E-02
Excess Air For Combustor (% stoich.)	0
HRSG Outlet Temperature (deg. C)	121.1
Steam Cycle Heat Rate, HHV (*1) (kJ/kWh)	9496

Cooling Water Temperature Rise (deg. C)	11.11
Auxiliary Heat Exchanger Load (*2) (%)	1.41
Total Steam Turbine Output (MWg)	0
Power Requirement (% MWg)	2
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	63.82
%PFC Allocated to Materials (%PFC)	2.46
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	9.057
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	1.472
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0

APPENDIX D: PC SENSITIVITY ANALYSIS PARAMETERS

Fuel Cost	60
Capacity factor	90.00
Ambient air temperature	18.89
relative humidity	50.00%
discount rate (before taxes)	0.07
plant or project book life	30.00
land cost use	3000.00
total land requirement	0.52
construction time	3.00
activated carbon	2417.00
MEA	2589.00
SCR catalyst	6003.00
boiler efficiency	90.00
excess air for furnace	20.00
leakage air at preheater	10.00
Percent ash entering flue gas stream	65.00%
Sorbent Concentration (wt %)	30.00
Lean CO2 Loading (mol CO2/mol sorb)	0.20
Sorbent Losses (excluding acid gasses) (kg/tonne CO2)	2.25
Sorbent Recovered (kg/tonne CO2)	0.20
Gas Phase Pressure Drop (MPa)	0.01
ID Fan Efficiency (%)	75.00
Activated Carbon Used (kg/tonne CO2)	0.08
Regenerator Heat Requirement (kJ/kg CO2)	4722.00
Regenerator Steam Heat Content (kJ/kg steam)	3194.00
Pump Efficiency (%)	75.00
Percent Solids in Reclaimer Waste (%)	40.00
CO2 Product Pressure (MPa)	13.79
CO2 Compressor Efficiency (%)	80.00
CO2 Unit Compression Energy (kWh/tonne CO2)	117.90
Construction Time (years)	3.00
Sorbent Cost ($/tonne)	2589.00
Inhibitor Cost (% of MEA)	20.00
Activated Carbon Cost ($/tonne)	2417.00
Caustic (NaOH) Cost ($/tonne)	499.20
Water Cost ($/kliter)	0.30
Number of Operating Jobs (jobs/shift)	2.00
Number of Operating Shifts (shifts/day)	4.75
Total Pipeline Length (km)	100.00
Booster Pump Efficiency (%)	75.00
Design Pipeline Flow (tonne/yr)	5439000.00
Actual Pipeline Flow (tonne/yr)	4896000.00

Inlet Pressure (@ power plant) (MPa)	13.79
Min Outlet Pressure (@ storage site) (MPa)	10.30
Average Ground Temperature (deg. C)	5.60
Pipe Material Roughness (centimeters)	0.00
Construction Time (years)	3.00
Booster Pump Operating Cost (%PFC)	1.50
Fixed O&M Cost ($/km-yr)	3100.00
Reservoir Depth (meters)	1219.00
Reservoir Thickness (meters)	304.80
Reservoir Horizontal Permeability (mD)	100.00
Reservoir Porosity (%)	12.00
Storage Coefficient (%)	5.80
Reservoir Surface Temperature (deg. C)	45.44
Geographical Area for CO2 Storage (sq km)	70190.00
Project Average Injection Rate (Mt CO2/yr)	4.90
Design Maximum Injection Rate per Well (Mt CO2/yr)	6.12
Operation Duration (years)	30.00
Miscellaneous Operations (%)	1.00
PISC and Site Closure Duration (years)	50.00
Well Seismic: VSP Tool Costs ($/well)	300000.00
Miscellaneous PISC and Site Closure (%)	0.50

APPENDIX E: IGCC SENSITIVITY ANALYSIS PARAMETERS

Parameter	Base Case
Capacity Factor (%)	90
Ambient Air Temperature (Dry Bulb Average) (deg. C)	18.89
Ambient Air Pressure (MPa)	0.1014
Relative Humidity (Average) (%)	50
Plant or Project Book Life (years)	30
Total Delivered Cost (as-fired) ($/tonne)	55.39
Oxygen (O2) (vol %)	95
Gasifier Temperature (deg. C)	1343
Gasifier Pressure (MPa)	4.24
Oxygen Input from ASU (mol O2/mol C)	0.4257
Total Carbon in Slag (%)	3
H2S Removal Efficiency (%)	98
Max Syngas Capacity per Train (tonne/hr)	225.2
Sulfur Recovery Efficiency (%)	95
H2S Removal Efficiency (%)	94
CO2 Product Pressure (MPa)	13.79
Turbine Inlet Temperature (deg. C)	1371
HRSG Outlet Temperature (deg. C)	121.1

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